TRANSCANADA CORP
Form 40-F
February 17, 2011

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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, 2010** Commission File Number **1-31690**

TRANSCANADA CORPORATION

(Exact Name of Registrant as specified in its charter)

Canada

(Jurisdiction of incorporation or organization)

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

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

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

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:

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

Securities registered pursuant to Section 12(g) of the Act: **None**
Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **None**

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

ý Annual Information Form ý Audited annual financial statements

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

At December 31, 2010, 696,229,462 common shares;
22,000,000 Cumulative Redeemable First Preferred Shares, Series 1;
14,000,000 Cumulative Redeemable First Preferred Shares, Series 3; and
14,000,000 Cumulative Redeemable First Preferred Shares, Series 5
were issued and outstanding

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

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Date File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files). Yes o No o

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

Form	**Registration No.**
S-8	333-5916
S-8	333-8470
S-8	333-9130
S-8	333-151736
F-3	33-13564
F-3	333-6132
F-10	333-151781
F-10	333-161929

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

Except sections specifically referenced below which shall be deemed incorporated by reference herein and filed, no other portion of the TransCanada Annual Report to Shareholder except as otherwise specifically incorporated by reference in the TransCanada Annual Information Form shall be deemed filed with the U.S. Securities and Exchange Commission (the "Commission") as part of this report under the Exchange Act.

A. Audited Annual Financial Statements

For audited consolidated financial statements, including the auditors' report, see pages 97 through 150 of the TransCanada 2010 Annual Report to Shareholders 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 attached as document 13.4.

B. Management's Discussion & Analysis

For management's discussion and analysis, see pages 6 through 96 of the TransCanada 2010 Annual Report to Shareholders included herein under the heading "Management's Discussion & Analysis".

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

For information on management's internal control over financial reporting, see Management's Report on Internal Control Over Financial Reporting attached as document 13.6.

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 pages 83 and 84 of the TransCanada 2010 Annual Report to Shareholders.

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 2010 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 pages 31 and 30, respectively, of the TransCanada 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 62 of the TransCanada 2010 Annual Report to Shareholders.

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 TransCanada securityholders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada'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, projects, and financial performance of TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada'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 TransCanada to successfully implement its strategic initiatives and whether such strategic initiatives will yield the expected benefits, the operating performance of TransCanada'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, which could cause TransCanada'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 TransCanada's Management's Discussion and Analysis filed as document 13.2 hereto including under the headings "Natural Gas Pipelines Opportunities and Developments", "Natural Gas Pipelines Business Risks", "Oil Pipelines Opportunities and Developments", "Oil 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 TransCanada with Canadian securities regulators and with the Commission. 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 document or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada 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 CORPORATION

Per: /s/ DONALD R. MARCHAND

DONALD R. MARCHAND
Executive Vice-President and Chief Financial Officer

Date: February 16, 2011

DOCUMENTS FILED AS PART OF THIS REPORT

13.1 TransCanada Corporation Annual Information Form for the year ended December 31, 2010.

13.2 Management's Discussion and Analysis (included on pages 6 through 96 of the TransCanada 2010 Annual Report to Shareholders).

13.3 2010 Audited Consolidated Financial Statements (included on pages 97 through 150 of the TransCanada 2010 Annual Report to Shareholders), including the auditors' report thereon.

13.4 Related supplementary note entitled "Reconciliation to United States GAAP".

13.5 Independent Auditors' Report of Registered Public Accounting Firm on the 2010 Audited Consolidated Financial Statements and on the related supplementary note entitled "Reconciliation to United States GAAP".

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

13.7 Report of Independent Registered Public Accounting Firm on the effectiveness of TransCanada's Internal Control Over Financial Reporting, as at December 31, 2010.

EXHIBITS

23.1 Consent of KPMG LLP, Independent Registered Public Accountants.

31.1 Certification of Chief Executive Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.

31.2 Certification of Chief Financial Officer pursuant to Section 302 of the *Sarbanes-Oxley Act of 2002*.

32.1 Certification of Chief Executive Officer regarding Periodic Report containing Financial Statements.

32.2 Certification of Chief Financial Officer regarding Periodic Report containing Financial Statements.

TRANSCANADA CORPORATION

ANNUAL INFORMATION FORM

February 14, 2011

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PRESENTATION OF INFORMATION

Unless the context indicates otherwise, a reference in this Annual Information Form (AIF) to TransCanada or the Company includes TransCanada Corporation and the subsidiaries of TransCanada Corporation through which its various business operations are conducted. In particular, TransCanada includes references to TransCanada PipeLines Limited (TCPL). Where TransCanada is referred to with respect to actions that occurred prior to its 2003 plan of arrangement with TCPL, which is described below under the heading TransCanada Corporation Corporate Structure , these actions were taken by TCPL or its subsidiaries. The term subsidiary , when referred to in this AIF, with reference to TransCanada means direct and indirect wholly owned subsidiaries of, and legal 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, 2010 (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 TransCanada s Management s Discussion and Analysis dated February 14, 2011 (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 TransCanada s profile.

The Canadian Institute of Chartered Accountants (CICA) Accounting Standards Board (AcSB) previously 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. As a United States (U.S.) Securities and Exchange Commission (SEC) registrant, TransCanada prepares and files a Reconciliation to United States GAAP and has the option to prepare and file its consolidated financial statements using U.S. generally accepted accounting principles (U.S. GAAP). Previously, TransCanada disclosed that effective January 1, 2011, the Company expected to begin reporting under IFRS. As a result of the developments noted below, management expects that the Company will adopt U.S. GAAP effective January 1, 2012. The Company s IFRS conversion project was proceeding as planned to meet the conversion date of January 1, 2011, prior to these developments. In accordance with Canadian GAAP, TransCanada follows specific accounting policies unique to a rate-regulated business. These rate-regulated accounting (RRA) standards allow the timing of recognition of certain expenses and revenues to differ from the timing that may otherwise be expected in a non-rate-regulated business under Canadian GAAP, in order to appropriately reflect the economic impact of regulators decisions regarding the Company s revenues and tolls. In October 2010, the AcSB and the Canadian Securities Administrators (CSA) amended their policies applicable to Canadian publicly accountable enterprises that use RRA in order to permit these entities to defer the adoption of IFRS for one year. Due to the continued uncertainty around the timing, scope and eventual adoption of an RRA standard under IFRS, TransCanada will defer its adoption of IFRS accordingly and continue preparing its consolidated financial statements in 2011 in accordance with Canadian GAAP, as defined by Part V of the CICA Handbook, in order to continue using RRA. TransCanada will continue to actively monitor IASB developments with respect to RRA and other IFRS. The impact of adopting U.S. GAAP is consistent with that currently reported in the Company s publicly filed Reconciliation to United States GAAP. Significant changes to existing systems and processes are not required to implement U.S. GAAP as the Company s primary accounting standard. For more information on TransCanada s conversion project, see TransCanada s MD&A under the headings Accounting Changes Future Accounting Changes International Financial Reporting Standards and Accounting Changes Future Accounting Changes U.S. GAAP Conversion Project .

Information in relation 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-lo statements in this document are intended to provide TransCanada securityholders and potential investors with information regarding TransCanada and its subsidiaries, including management s assessment of TransCanada 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 TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada 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 TransCanada 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 the heading Risk Factors , which could cause TransCanada 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 TransCanada with Canadian securities regulators and with the 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 AIF or otherwise, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada 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 CORPORATION

Corporate Structure

TransCanada s head office and registered office are located at 450 1st Street S.W., Calgary, Alberta, T2P 5H1. TransCanada was incorporated pursuant to the provisions of the *Canada Business Corporations Act* (CBCA) on February 25, 2003 in connection with a plan of arrangement which established TransCanada as the parent company of TCPL. The arrangement was approved by TCPL common shareholders on April 25, 2003 and, following court approval and the filing of Articles of Arrangement, the arrangement became effective May 15, 2003. Pursuant to the arrangement, the common shareholders of TCPL exchanged each of their TCPL common shares for one common share of TransCanada (Common Share(s)). The debt securities and preferred shares of TCPL remained obligations and securities of TCPL. TCPL continues to hold the assets it held prior to the arrangement and continues to carry on business as the principal operating subsidiary of the TransCanada group of entities. TransCanada does not hold any material assets directly other than the common shares of TCPL and receivables from certain of TransCanada s subsidiaries.

Intercorporate Relationships

The following diagram presents the name and jurisdiction of incorporation, continuance or formation of TransCanada s principal subsidiaries as at December 31, 2010. Each of the subsidiaries shown has total assets that exceeded 10 per cent of the total consolidated assets of TransCanada or revenues that exceeded 10 per cent of the total consolidated revenues of TransCanada as at and for the year ended December 31, 2010. TransCanada owns, directly or indirectly, 100 per cent of the voting shares in each of each of these subsidiaries, with exception to TransCanada Keystone Pipeline, LP which TransCanada indirectly holds 100 per cent of the partnership interests thereof.

The above diagram does not include all of the subsidiaries of TransCanada. The assets and revenues of excluded subsidiaries in the aggregate did not exceed 20 per cent of the total consolidated assets or total consolidated revenues of TransCanada as at and for the year ended December 31, 2010.

GENERAL DEVELOPMENT OF THE BUSINESS

Commencing in 2011, TransCanada s reportable business segments are Natural Gas Pipelines , Energy and Oil Pipelines . Natural Gas and Oil Pipelines are principally comprised of the Company s respective natural gas and oil 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 in Canada.

TransCanada s strategy in Natural Gas and Oil Pipelines is focused on growing its North American natural gas and crude oil transmission network and maximizing the long-term value of its existing pipeline assets. The Company 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 the U.S. More recently, TransCanada has also developed a substantial non-regulated natural gas storage business in Alberta.

Summarized below are significant developments that have occurred in TransCanada s Natural Gas Pipelines, Oil Pipelines and Energy businesses, respectively, and the significant acquisitions, dispositions, events or conditions which have had an influence on that development, during the last three financial years.

Developments in the Natural Gas Pipelines Business

Date	Description of Development
CANADIAN MAINLINE (Canadian Mainline)	
March 2008	The National Energy Board (NEB) approved the amended interim tolls for Canadian Mainline effective April 1, 2008. TransCanada had filed an application with the NEB to increase the interim tolls previously approved in December 2007. This toll increase was a result of a significant decrease in forecasted flows on the system and was intended to allow TransCanada to meet its 2008 revenue requirement.
December 2009	The NEB approved TransCanada s application for 2010 final tolls for Canadian Mainline, effective January 1, 2010. The 2010 calculated return on equity was 8.52 per cent. Reduced throughput and greater use of shorter distance transportation contracts resulted in an increase in its tolls for 2010 compared to 2009.
August 2010	TransCanada s open season to transport Marcellus volumes on the Canadian Mainline closed. The open season was initiated at the request of prospective shippers.
December 2010	TransCanada filed an application with the NEB for approval of the interim 2011 tolls for the Canadian Mainline which contained certain changes to the tolling mechanism to reduce long haul tolls. The NEB decided not to approve the tolls as requested in the interim tolls application and set the current 2010 tolls as interim commencing January 1, 2011.
January 2011	TransCanada filed for revised interim tolls effective March 1, 2011 based on the existing 2007 2011 settlement with customers. If approved, the revised interim tolls will allow for collection of revenues that will more closely reflect TransCanada s costs and forecast throughput in 2011. TransCanada is continuing its discussions with stakeholders with the intent of increasing the level of support for a potential settlement and expects to file a subsequent application for final 2011 tolls for the Canadian Mainline later in 2011.
ALBERTA SYSTEM (Alberta System)	
April 2008	An expansion of the Alberta System in the Fort McMurray area was placed in service on its projected on-stream date.
February 2009	The NEB approved TransCanada s June 2008 application for federal regulation of the Alberta System effective April 29, 2009.
June 2010	TransCanada reached a three year settlement agreement with the Alberta System shippers and other interested parties and filed a 2010-2012 Revenue Requirement Settlement Application with the NEB.
August 2010	The NEB approved TransCanada s November 2009 application for the Alberta System s Rate Design Settlement and the commercial integration of the ATCO Pipeline system with the Alberta System.
September 2010	The NEB approved the Alberta System s 2010-2012 Revenue Requirement Settlement Application.
October 2010	The NEB approved final 2010 rates for the Alberta System, which reflect the Alberta System 2010-2012 Revenue Requirement Settlement and Rate Design Settlement.
December 2010	The NEB approved the interim 2011 tolls for the Alberta System reflecting the 2010-2012 Revenue Requirement Settlement and continuing to transition to the toll methodology approved in the Rate Design Settlement. TransCanada expects to file for final 2011 tolls on the Alberta System which will reflect the outcome of further discussions with stakeholders with respect to 2011 tolls and commercial integration of the ATCO Pipeline system.
North Central Corridor Expansion (North Central Corridor)	
October 2008	The Alberta Utilities Commission (AUC), which previously regulated the Alberta System, approved TransCanada s application for a permit to construct the North Central Corridor.

October 2008	Construction of the North Central Corridor commenced.
May 2009	The 140 kilometer (km) North Star section of the North Central Corridor was completed.
September 2009	Work on the final phase of the North Central Corridor commenced.
March 2010	The North Central Corridor was completed, on schedule and under budget.

Groundbirch Pipeline Project (Groundbirch)

March 2010	The NEB approved TransCanada s application after a public hearing, to construct and operate Groundbirch.
August 2010	TransCanada received final regulatory approvals and commenced construction of Groundbirch.
December 2010	Groundbirch was completed on schedule and under budget, and began transporting natural gas from the Montenay shale gas formation into the Alberta System.

Date	Description of Development
Horn River Pipeline Project (Horn River)	
February 2009	TransCanada 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 pipeline.
February 2010	TransCanada filed an application with the NEB for approval to construct and operate the pipeline.
April 2010	The NEB announced that it would hold a public hearing process on TransCanada s February 2010 application for approval to construct and operate the pipeline. The NEB hearing relating to the Horn River pipeline concluded in November 2010.
January 2011	TransCanada received approval from the NEB to construct the Horn River pipeline.
FOOTHILLS SYSTEM (Foothills System)	
June 2010	TransCanada reached an agreement to establish a cost of capital for Foothills System. The NEB approved final tolls for 2010, effective July 1, 2010.
MACKENZIE GAS PIPELINE PROJECT (Mackenzie Gas Project)	
December 2009	A Joint Review Panel of the Canadian government released a report on environmental and socio-economic factors in relation to the Mackenzie Gas Project. The report was submitted to the NEB as part of the review process for approval of the project.
December 2010	The NEB approved the proponents application to construct the Mackenzie Gas Project subject to numerous conditions.
ALASKA PIPELINE PROJECT (Alaska Pipeline)	
December 2008	The Alaska Commissioners of Revenue and Natural Resources issued the *Alaska Gasline Inducement Act* (AGIA) license to TransCanada to advance the Alaska Pipeline. Subsequently, TransCanada 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 TransCanada to a maximum of US$500 million.
June 2009	TransCanada reached an agreement with ExxonMobil Corporation (ExxonMobil) to jointly advance the Alaska Pipeline. A joint project team is developing the engineering, environmental, aboriginal relations and commercial work.
April 2010	The Alaska Pipeline open season commenced.
Third Quarter 2010	Interested shippers on the proposed Alaska Pipeline project submitted conditional commercial bids in the open season that closed July 30, 2010. The project is now working with shippers to resolve those conditions within the project s control.
BISON PIPELINE (Bison)	
September 2008	TransCanada 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.
December 2010	Construction of Bison was completed.
January 2011	Bison was placed in commercial service upon receiving final regulatory approvals to commence operations.
GREAT LAKES SYSTEM (Great Lakes System)	
November 2009	The U.S. Federal Energy Regulatory Commission (FERC) initiated an investigation to determine whether rates on the Great Lakes System were just and reasonable. In response, Great Lakes Gas Transmission Limited Partnership (Great Lakes) filed a cost and revenue study with the FERC in February 2010.
July 2010	FERC approved, without modification, the settlement stipulation agreement reached among Great Lakes, active participants and the FERC trial staff. As approved, the stipulation and agreement applies to all current and future shippers on the Great Lakes System.
NORTH BAJA SYSTEM (North Baja System)	

July 2009	TransCanada completed the sale of North Baja Pipeline, LLC (North Baja) to its affiliate, TC PipeLines, LP. As part of the transaction, TransCanada agreed to amend its incentive distribution rights with TC PipeLines, LP. Under the amendment, TransCanada 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.
GUADALAJARA (Guadalajara)	
May 2009	TransCanada announced that it was the successful bidder on a contract to build, own and operate the Guadalajara pipeline.
December 2010	The Guadalajara pipeline was 70 per cent complete at Year End.

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

Developments in the Oil Pipelines Business

Date	Description of Development
KEYSTONE	
2008	TransCanada increased its equity ownership in TransCanada Keystone Pipeline, LP (Keystone U.S.) and TransCanada Keystone Pipeline Limited Partnership (Keystone Canada) to 79.99 per cent from 50 per cent with ConocoPhillips equity ownership being reduced concurrently to 20.01 per cent.
March 2008	Keystone U.S. received a Presidential Permit authorizing the construction, maintenance and operation of facilities at the U.S. and Canada border for the transportation of crude oil between the two countries. The Presidential Permit, was issued following the issuance by the U.S. Department of State of the Final Environmental Impact Statement on January 11, 2008 for the construction of the Keystone U.S. pipeline and its Cushing extension (the Cushing Extension).
June 2008	The NEB approved the application for additional pumping facilities required to expand the Canadian portion of Keystone (as defined below and referred to in this section as Keystone) from approximately 435,000 barrels per day (Bbl/d) to 591,000 Bbl/d to accommodate volumes to be delivered to the Cushing markets.
July 2008	TransCanada announced plans for Keystone U.S. Gulf Coast expansion (the U.S. Gulf Coast Expansion) to provide additional capacity in 2013 of 500,000 Bbl/d from Western Canada to the U.S. Gulf Coast, near existing terminals in Port Arthur, Texas.
October 2008	The Company successfully conducted an open season for the U.S. Gulf Coast Expansion by securing additional firm, long term transportation contracts.
August 2009	TransCanada became sole owner of Keystone project through the purchase of ConocoPhillips remaining interest (approximately 20 per cent) for US$553 million and the assumption of US$197 million of short-term debt.
March 2010	The NEB approved TransCanada s application to construct and operate the Canadian portion of the U.S. Gulf Coast Expansion.
April 2010	The U.S. Department of State issued a Draft Environmental Impact Statement for the U.S. Gulf Coast Expansion.
June 2010	Keystone oil pipeline commenced operating at a reduced maximum operating pressure as the first phase of Keystone began delivering oil to Wood River and Patoka in Illinois (Wood River/Patoka).
November 2010	The open season for the Bakken Marketlink (Bakken Marketlink) project, which commenced in September 2010, closed successfully. The Company secured firm, five year shipper contracts of 65,000 Bbl/d.
November 2010	The open season for the Cushing Marketlink (Cushing Marketlink) project, which commenced in September 2010, closed successfully. The Company secured contractual support sufficient to proceed with the Cushing Marketlink project, which would when completed have the ability to provide 150,000 Bbl/d of crude oil from Cushing, Oklahoma to the U.S. Gulf Coast.
December 2010	The reduced maximum operating pressure restriction on the Canadian conversion phase of the base Keystone oil pipeline was removed by the NEB following the completion of in-line inspections.
Fourth Quarter 2010	Construction of the Cushing Extension was completed, and line fill commenced in late 2010.
January 2011	The required operational modifications were completed on the Wood River/Patoka phase of Keystone oil pipeline. As a result, the system was capable of operating at the approved design pressure and the Company commenced recording earnings for the Wood River/Patoka phase in February 2011.
February 2011	The commercial in service of the Cushing Extension commenced.

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

Developments in the Energy Business

Date	Description of Development
RAVENSWOOD GENERATING STATION (Ravenswood)	
August 2008	TransCanada completed its acquisition of Ravenswood for US$2.9 billion, subject to certain post-closing adjustments, pursuant to a purchase agreement with KeySpan Corporation and certain subsidiaries.
BÉCANOUR (Bécancour)	
June 2010	Hydro-Québec Distribution (Hydro-Québec) notified TransCanada it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2011. Hydro-Québec had previously announced that it would exercise its option to extend the agreement to suspend all electricity generation from Bécancour throughout 2010. Under the original agreement, 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. TransCanada will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.
BRUCE POWER (Bruce Power)	
January 2008	The sixteenth and final new steam generator was installed in Bruce A (as defined below and referred in this section as Bruce A) Units 1 and 2.
Fourth Quarter 2008	A review of the end of life estimates for Units 3 and 4 was completed. 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.
July 2009	Bruce Power and the Ontario Power Authority (OPA) amended certain terms and conditions included in the Bruce Power Refurbishment Implementation Agreement. The amendments were 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 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 Bruce B (as defined below and referred in this section as 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.
October 2010	The last of the 960 calandria tubes were successfully installed in Bruce A Units 1 and 2.
December 2010	The last of the fuel channel assemblies into Bruce A Unit 2 were successfully installed.
February 2011	A maintenance outage of approximately three weeks commenced on February 1, 2011 on Bruce B Unit 8 and outages of approximately seven weeks each are scheduled to begin in mid-April 2011 for Bruce B Unit 7 and mid-October 2011 for Bruce B Unit 5. Bruce A expects an outage of approximately one week on Unit 3 in July 2011 and, following approval from the Canadian Nuclear Safety Commission the West Shift Plus outage of approximately six months is scheduled to commence in early November 2011 on Unit 3. The West Shift Plus outage is a key part of the life extension strategy for Unit 3 and is an extension of the West Shift program which was successfully executed in 2009. Subject to

	regulatory approval, Bruce Power expects to load fuel into Unit 2 in second quarter 2011 and achieve a first synchronization of the generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce Power expects to load fuel into Unit 1 in third quarter 2011, with a first synchronization of the generator during first quarter 2012 and commercial operation expected to occur during third quarter 2012. Plant commissioning and testing are underway and will accelerate in second quarter 2011 when construction activities are essentially complete.
February 2011	The Bruce Power Refurbishment Implementation Agreement was amended to reflect: the suspension date for contingent support payments on Bruce A output was extended to June 1, 2012 from December 31, 2011, and as a result, all output from Bruce A will receive spot prices from June 1, 2012 until the restart of Units 1 and 2 is complete; and a recovery of costs incurred by Bruce A in connection with development of fuel programs.
PORTLANDS ENERGY CENTRE (Portlands Energy)	
April 2009	Portlands Energy was fully commissioned, ahead of time and under budget.
OAKVILLE GENERATING STATION	
September 2009	The OPA advised TransCanada that it was awarded a 20 year Clean Energy Supply contract to build, own and operate a 900 MW a generating station in Oakville, Ontario.
October 2010	The Government of Ontario announced that it would not proceed with the Oakville generating station. TransCanada commenced negotiations with the OPA on a settlement which would terminate the Clean Energy Supply contract and compensate TransCanada for the economic consequences associated with the contract s termination.

Date	Description of Development
CARTIER WIND (Cartier Wind)	
November 2008	The 109 MW Carleton wind farm, the third of five phases of Cartier Wind, became operational.
Third Quarter 2009	Construction activity began on the Cartier Wind s 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms. The Montagne-Sèche project and phase one of the Gros-Morne project are expected to be operational in 2011, and phase two of the Gros-Morne project is expected to be operational in 2012, subject to the necessary approvals.
COOLIDGE (Coolidge)	
May 2008	TransCanada 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.
December 2008	The Arizona Corporation Commission granted a Certificate of Environmental Compatibility approving Coolidge.
August 2009	TransCanada began construction of Coolidge.
December 2010	At Year End, construction of Coolidge was approximately 95 per cent complete and commissioning was approximately 80 per cent finished.
KIBBY WIND (Kibby Wind)	
July 2008	Kibby Wind received unanimous final development plan approval from Maine s Land Use Regulation Commission.
October 2009	The first phase of Kibby Wind, including 22 turbines capable of producing a combined 66 MW of power, was completed and placed in service ahead of schedule and under budget.
October 2010	The 66 MW second phase of the Kibby Wind was completed and placed in service. This phase included the installation of an additional 22 turbines, ahead of schedule and on budget.
SUNDANCE (Sundance)	
February 2011	On February 8, 2011, TransCanada received from TransAlta Corporation (TransAlta) notice under the Sundance A power purchase arrangement that TransAlta has determined that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored and that TransAlta therefore seeks to terminate the power purchase arrangement in respect of those units. TransCanada has not received any information that would validate TransAlta s determination that the units cannot be economically restored to service. TransCanada has 10 business days from the date of TransAlta s notice to either agree with or dispute TransAlta s determination that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored. TransCanada will assess any information provided by TransAlta during this 10-day period. If TransCanada disputes TransAlta s determination, the issue will be resolved using the dispute resolution procedure under the terms of the power purchase arrangement. In December 2010, the Sundance 1 and 2 generating units were withdrawn from service for testing. In January 2011, these same units were subject to a force majeure claim by TransAlta under the power purchase arrangement. TransCanada has received insufficient information to make an assessment of TransAlta s force majeure claim and therefore has recorded revenues under the power purchase arrangement as though this event was a normal plant outage.
Second Quarter 2010	Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components that the facility operator, TransAlta, has asserted is a force majeure event. TransCanada has received no information that validates a claim of force majeure and therefore has recorded revenues under the power purchase arrangement as though this event was a normal plant outage. TransCanada is pursuing the remedies available to it under the terms of the power purchase arrangement.

HALTON HILLS GENERATING STATION (Halton Hills)

September 2010	Halton Hills, which was constructed pursuant to a 20 year Clean Energy Supply contract with the OPA in November 2006, was completed and placed in service.

ZEPHYR (Zephyr) AND CHINOOK (Chinook) POWER TRANSMISSION LINES

February 2009	The FERC approved the application filed by TransCanada in December 2008 requesting approval to charge negotiated rates and to proceed with open seasons in the spring of 2009 for Zephyr and Chinook, respectively. Zephyr is a proposed 1,609 km (1,000 mile), 500 kilovolt high voltage direct current (HVDC) line that would be capable of delivering primarily wind generated power from Wyoming to Nevada. Chinook is a proposed 1,609 km (1,000 miles), 500 kilovolt HVDC line that would be capable of delivering primarily wind generated power to markets from Montana to Nevada. The open seasons commenced in October 2009.
May 2010	TransCanada concluded a successful open season for Zephyr. Support from key markets and a positive regulatory environment are necessary before the significant siting and permitting activities required to construct Zephyr will commence and TransCanada anticipates making a decision on whether to proceed in 2011.
December 2010	TransCanada closed the open season for Chinook without allocating capacity to Montana shippers. TransCanada continues to advance the Chinook project, and discussions with Montana wind developers and other market participants is ongoing.

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

BUSINESS OF TRANSCANADA

TransCanada is a leading North American energy infrastructure company focused on Natural Gas Pipelines, Oil Pipelines and Energy. At Year End, Natural Gas Pipelines accounted for approximately 54 per cent of revenues and 51 per cent of TransCanada s total assets, Oil Pipelines had not yet recorded any revenues but accounted for 18 per cent of TransCanada s total assets and Energy accounted for approximately 46 per cent of revenues and 28 per cent of TransCanada s total assets. The following is a description of each of TransCanada s three main areas of operation.

The following table shows TransCanada s revenues from operations by segment, classified geographically, for the years ended December 31, 2010 and 2009.

Revenues From Operations *(millions of dollars)*	**2010**	**2009**
Natural Gas Pipelines		
Canada - Domestic	$2,125	$2,389
Canada - Export(1)	837	755
United States and other	1,411	1,585
	4,373	4,729
Oil Pipelines	Nil	Nil
Energy(2)		
Canada Domestic	2,243	2,690

Canada - Export(1)	1	1
United States and other	1,447	761
	3,691	3,452
Total Revenues(3)	$8,064	$8,181

(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.

Natural Gas Pipelines Business

TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and regulated gas storage facilities. TransCanada s network of wholly owned natural gas pipelines extends more than 60,000 km (37,000 miles), and its partially owned natural gas pipelines extend more than 8,800 km (5,500 miles), tapping into virtually all major gas supply basins in North America. TransCanada has substantial Canadian and U.S. natural gas pipeline and related holdings, including those listed below. The following natural gas pipelines are owned 100 per cent by TransCanada unless otherwise stated.

TransCanada has the following natural gas pipelines and related holdings in Canada:

• TransCanada 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.

• TransCanada s Alberta System is a natural gas transmission system in Alberta and Northeast British Columbia (B.C.) which gathers natural gas for use within the province of Alberta 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 24,187 km (15,029 mile) Alberta System is one of the largest carriers of natural gas in North America. During the past three completed financial years TransCanada has enhanced the Alberta System as follows:

o North Central Corridor, which extends the northern section of the Alberta System, was completed in March 2010; and

o TransCanada continues to advance further pipeline development in B.C. and Alberta to transport unconventional shale gas supply as follows:

• Groundbirch was completed in December 2010, connecting the Alberta System to natural gas supplies from the Montney shale gas formation in Northeast B.C. TransCanada has entered into firm transportation agreements with Groundbirch pipeline customers for 1.24 billion cubic feet per day (Bcf/d) by 2014;

- TransCanada has applied to build the proposed Horn River pipeline, an extension of the Alberta System to serve production from the new shale gas supply in the Horn River basin north of Fort Nelson, B.C. TransCanada received approval from the NEB to construct the Horn River pipeline in January 2011. The Horn River pipeline is scheduled to be operational in second quarter 2012 with commitments for contracted natural gas of over 634 MMcf/d by 2014; and

- the Company has received requests for additional natural gas transmission service throughout the northwest portion of the Western Canadian Sedimentary Basin, including the Horn River and Montney areas of B.C. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

- TransCanada 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.

- TransCanada Pipeline Ventures LP owns a 161 km (100 mile) pipeline and related facilities that supply natural gas to the oil sands region near Fort McMurray, Alberta as well as a 27 km (17 mile) pipeline that supplies natural gas to a petrochemical complex at Joffre, Alberta.

- TQM (TQM) is 50 per cent owned by TransCanada. TQM is a 572 km (355 mile) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with the Portland System. TQM is operated by TransCanada.

- The Mackenzie Gas Project is a proposed natural gas pipeline extending 1,196 km (743 mile) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

TransCanada has the following natural gas pipeline and related holdings in the U.S.:

- The proposed Alaska Pipeline is a 4.5 Bcf/d natural gas pipeline and treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the natural gas treatment plant at Prudhoe Bay, Alaska to Alberta, or an alternative pipeline to Valdez, Alaska. TransCanada received approval of its plan to conduct an open season from the FERC in March 2010. An open season commenced at the end of April 2010, and continued until July 2010. TransCanada is continuing to negotiate with potential shippers from the initial open season. The Alaska Pipeline project is a joint effort between TransCanada and ExxonMobil pursuant to the AGIA.

- TransCanada 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 in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. Midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. ANR System 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 American Natural Resources Company and ANR Storage Company (collectively, *ANR*) provide regulated gas storage services to customers on the ANR System and the Great Lakes System in upper Michigan. In total, the ANR business unit owns and operates natural gas storage facilities throughout the State of Michigan with total natural gas storage capacity of 250 billion cubic feet (Bcf).

- The GTN System (GTN System) is TransCanada s 2,178 km (1,353 miles) natural gas transmission system that transports Western Canada Sedimentary Basin and Rocky Mountain sourced natural gas to third party natural gas pipelines and markets in Washington, Oregon and California, and connects with the Tuscarora Gas Transmission Company (Tuscarora) pipeline.

- The Bison pipeline is a 487 km (303 mile) natural gas pipeline from the Powder River Basin in Wyoming connecting to the Northern Border Pipeline System (NBPL System) in Morton County, North Dakota. The Company commenced construction of the Bison pipeline in July 2010 and the pipeline became operational in January 2011. The Bison pipeline has long term shipping commitments for 407 MMcf/d.

- The Great Lakes System is a 3,404 km (2,115 mile) natural gas transmission system connecting to the Canadian Mainline and serves markets primarily in Eastern Canada and the Northeastern and Midwestern U.S. TransCanada 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 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. TransCanada 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. TransCanada operates the Tuscarora System (Tuscarora System) a 491 km (305 mile) pipeline system transporting natural gas from the GTN System at Malin, Oregon to Wadsworth, Nevada, with delivery points in Northeastern California and Northwestern Nevada. TransCanada 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. TransCanada operates the North Baja System, a natural gas transmission system which extends 138 km (86 miles) from Ehrenberg, Arizona to a point near Ogilby, California on the California/Mexico border and connects with a third party natural gas pipeline system in Mexico. TransCanada effectively owns 38.2 per cent of the same through its 38.2 per cent interest in TC PipeLines, LP.

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

- The Portland System (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. TransCanada has a 61.7 per cent ownership interest in the Portland System and operates this pipeline.

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

TransCanada 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. TransCanada holds a 46.5 per cent ownership interest in this pipeline.

- Owned 30 per cent by TransCanada, Gas Pacifico is a 540 km (336 mile) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada 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.

- 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) transporting natural gas from a LNG terminal under construction near Manzanillo on Mexico s Pacific coast to Guadalajara, the second largest city in Mexico. The Guadalajara pipeline is supported by a twenty-five year contract for its entire capacity with Comisión Federal de Electridad, Mexico s state-owned electric power company. Guadalajara pipeline has an expected in service date of mid-2011 and was 70 per cent complete at Year End.

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

Oil Pipelines Business

With increasing production from crude oil sands in Alberta and new crude oil discoveries in the U.S., including the Bakken shale play in Montana and North Dakota, along with growing demand for secure, reliable sources of energy, TransCanada has identified opportunities to develop new oil pipeline capacity. The Company s Keystone crude oil pipeline and other opportunities in TransCanada s oil pipeline business are described below**.**

Keystone (Keystone) is a crude oil pipeline system designed to initially carry 1.1 million Bbl/d which is comprised of the completed 3,467 km (2,154 mile) Wood River/Patoka and Cushing Extension phases, and the proposed 2,673 (1,661 mile) U.S. Gulf Coast Expansion. The Wood River/Patoka phase transports crude oil from Hardisty, Alberta to U.S. Midwest markets at

Wood River and Patoka, Illinois and is designed for an initial nominal capacity of 435,000 Bbl/d. The Wood River/Patoka phase was placed in service in June 2010. The Cushing Extension extends the pipeline to Cushing, Oklahoma and increases nominal capacity to 591,000 Bbl/d if design capacity is achieved. The Cushing Extension was placed in service in February 2011. The proposed U.S. Gulf Coast Expansion, which would expand and extend Keystone from Hardisty to a delivery point near existing terminals in Port Arthur, Texas, is expected to provide additional pipeline capacity in 2013, pending U.S. regulatory approval.

The Company is pursuing the opportunity to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota for delivery to major U.S. refining markets. Following an open season conducted in the second half of 2010, the Company secured firm, five year shipper contracts totaling 65,000 Bbl/d for its proposed Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing, Oklahoma on facilities that form part of the U.S. Gulf Coast Expansion. Following an open season conducted in the second half of 2010, the Company secured contractual support sufficient to proceed with the Cushing Marketlink project, which would when completed transport up to 150,000 Bbl/d of crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the U.S. Gulf Coast Expansion. With these commitments, TransCanada will file for the necessary regulatory approvals in the U.S. to construct and operate the Bakken and Cushing Marketlink pipelines. Commercial in service is anticipated in 2013.

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

Regulation of the Natural Gas and Oil Pipelines Businesses

Canada

Under the terms of the *National Energy Board Act* (Canada), the Canadian Mainline, TQM, and the Foothills and Alberta systems (collectively referred to in this section as 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 TransCanada 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.

The NEB regulates the terms and conditions of service, including rates, and the physical operation of the Canadian portion of Keystone. NEB approval is also required for facility additions, such as the Canadian portion of the proposed U.S. Gulf Coast Expansion project which was approved by the NEB in March 2010.

United States

TransCanada s wholly owned and partially owned U.S. pipeline systems, including the ANR, GTN, Great Lakes, Iroquois, Portland, NBPL, North Baja and Tuscarora systems, are considered 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 transportation rates, on the U.S. portion of Keystone system. Certain states in which Keystone has right of ways also regulate construction and siting of Keystone.

Energy Business

The Energy segment of TransCanada 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 TransCanada has an interest in, including those under development, in the aggregate, represent more than 10,800 MW of power generation capacity. Power plants and power supply in Canadian power account for approximately 65 per cent of this total, and power plants in U.S. power account for the balance, being approximately 35 per cent.

TransCanada owns and operates the following facilities:

- Ravenswood generating station, 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 20 per cent of New York City s peak load.

- Halton Hills, a 683 MW natural gas-fired power plant in Halton Hills, Ontario, which was placed in service in September 2010. All of the power produced by the facility is sold to the OPA under a 20 year Clean Energy Supply contract.

- Kibby Wind, a 132 MW wind farm located in the Kibby and Skinner Townships in Maine. The first 66 MW phase of Kibby Wind was place in service in October 2009 and the second 66 MW phase was placed in service in October 2010.

- TC Hydro, TransCanada 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 (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 under a 20 year power purchase agreement 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 under an agreement entered into with Hydro-Québec. Under the agreement, TransCanada receives payments that are 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 TransCanada 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.

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

- TransCanada 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 arrangement that expires in 2017. TransCanada also has the rights to 50 per cent of the generating capacity of the 706 MW Sundance B facility under a power purchase arrangement, which expires in 2020. The Sundance A and Sundance B facilities are located in South Central Alberta.

- The Sheerness (Sheerness) facility, which consists of two coal-fired thermal power generating units, is located in Southeastern Alberta. TransCanada has the rights to 756 MW of generating capacity from the Sheerness power purchase arrangement that expires in 2020.

TransCanada has interests in the following:

- Two nuclear power generating stations, Bruce A, which is owned 48.8 per cent by TransCanada 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 TransCanada 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. The two units of Bruce A which are being refurbished are expected to re-commence commercial operations in first quarter and third quarter 2012.

- 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.

- Portlands Energy, a 550 MW, combined-cycle natural gas power plant located in Toronto, Ontario is 50 per cent owned by TransCanada. This facility, which was fully commissioned in April 2009, provides electricity under a 20 year Accelerated Clean Air Energy Supply contract with the OPA.

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

- The Cartier Wind energy project consists of five wind projects in the Gaspé region of Québec contracted by Hydro-Québec representing a total of 590 MW when complete. Three of the wind farms are in service, and two are currently under construction. The Montagne-Sèche project and phase one of the Gros-Morne project (101 MW) are expected to be operational in 2011, and phase two of the Gros-Morne project (111 MW) is expected to be operational in 2012, subject to the necessary approvals. Cartier Wind is 62 per cent owned by TransCanada. All of the power produced by Cartier Wind is sold to Hydro-Québec under a 20 year power purchase agreement.

- Coolidge is a simple-cycle, natural gas-fired peaking power generation station under construction in Coolidge, Arizona. Based on optimal operating conditions, TransCanada expects an electrical output of approximately 575 MW from this facility, designed to provide a quick response to peak power demands. Construction commenced in August 2009 and was approximately 95 per cent complete at Year End. The generating station is expected to be placed in service in accordance with its 20 year power purchase agreement with the Salt River Project Agricultural Improvement and Power District in second quarter 2011.

Further information about TransCanada s energy holdings and significant developments and opportunities in relation 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, TransCanada s principal operating subsidiary, TCPL, had approximately 4,230 full time active employees, substantially all of whom were employed in Canada and the U.S., as set forth in the following table.

Calgary	1,862
Western Canada (excluding Calgary)	460
Houston	453
U.S. Midwest	453
U.S. Northeast	409
Eastern Canada	264
U.S. Southeast/Gulf Coast	233

U.S. West Coast		86
Mexico and South America		10
	Total	**4,230**

Social and Environmental Policies

Health, safety and environment (HS&E) are top priorities in all of TransCanada s operations and activities. These areas are guided by the Company s HS&E Commitment Statement, which outlines guiding principles for a safe and healthy environment for TransCanada s employees, contractors and the public, and for TransCanada s commitment to protect the environment. All employees are responsible for TransCanada s HS&E performance. TransCanada 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. TransCanada 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. TransCanada 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. TransCanada is committed to respecting the diverse environments and cultures in which it operates and to support open communication with its stakeholders.

The Health, Safety and Environment Committee of the Board of Directors (the Board) monitors compliance with the Company s HS&E corporate policy through regular reporting. TransCanada 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. TransCanada 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.

As one of TransCanada s priorities, safety is an integral part of the way its employees work. In 2010, one of TransCanada s objectives was to sustain health and safety performance. Overall, TransCanada s safety frequency rates in 2010 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 brought into service only after all necessary requirements have been satisfied. The Company expects to spend approximately $250 million in 2011 for pipeline integrity on its wholly owned pipelines, an increase of approximately $95 million over 2010 primarily due to increased levels of in-line pipeline inspection on all systems and pipeline enhancements in areas of population encroachment. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB regulated pipelines are treated on a flow-through basis and, as a result, these expenditures have no impact on TransCanada s earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on TransCanada s earnings. Expenditures for GTN System may also be recovered through a cost recovery mechanism in its rates if threshold expenditures are achieved. TransCanada s pipeline safety record in 2010 continued to be above industry benchmarks. TransCanada experienced no pipeline breaks in 2010. 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.

Aboriginal and Stakeholder Relations

TransCanada has recognized the enhanced level of engagement of a wide variety of stakeholders in its business activities that can have a significant impact on the Company s ability to obtain approvals for new assets and to maintain its licences to operate. TransCanada has adopted a code of business ethics which applies to the Company s employees that is based on the Company s four core values of integrity, collaboration, responsibility and innovation, which guide the interaction between and among the Company s employees and serve as a standard for TransCanada in its dealings with all stakeholders. The code, which may be viewed on TransCanada s website at www.transcanada.com, sets out the fundamental principles of compliance with the law, fair dealing and a commitment to HS&E.

TransCanada s approach to stakeholder engagement is based on building relationships, mutual respect and trust while recognizing the unique values, needs and interests of each community. Key principles that guide TransCanada s engagement include: the Company s respect for the diversity of Aboriginal/Native American communities and recognition of the importance of the land to these communities; and the Company s belief in engaging stakeholders from the earliest stages of its projects, through the project development process and into operations.

Environmental Protection

TransCanada s facilities are subject to stringent federal, provincial, state and local environmental statutes and regulations regarding environmental protection, including requirements that establish compliance and remedial obligations. Such laws and regulations generally require facilities to obtain and comply with a wide variety of environmental restrictions, licences, permits and other approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of remedial requirements, and/or the issuance of orders respecting future operations. TransCanada has ongoing inspection programs designed to keep all of its facilities in compliance with environmental requirements.

At December 31, 2010, TransCanada recorded liabilities of approximately $84 million (2009 - $91 million) for remediation obligations and compliance costs associated with environmental regulations. 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.

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

In 2010, the Company owned assets in four regions , Alberta, Québec, B.C., and the Northeastern U.S., where regulations exist to address industrial greenhouse gas (GHG) emissions. TransCanada has procedures in place to address these regulations. In Alberta, under the *Specified Gas Emitters Regulation*, industrial facilities emitting GHGs over an intensity threshold level are required to reduce GHG emissions intensities by 12 per cent below an average baseline. TransCanada s Alberta-based facilities are subject to this regulation, as are the Sundance and Sheerness coal-fired power facilities with which TransCanada has power purchase arrangements. As an alternative to reducing emissions intensities, compliance can be achieved through acquiring offsets or making payments to a technology fund at a cost of $15 per tonne of carbon dioxide (CO_2) equivalents 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. Some of the compliance costs from the Company s power generation facilities in Alberta are recovered through market pricing and contract flow-through provisions. TransCanada has estimated and recorded related costs of $22 million for 2010, after contracted cost recovery.

In Québec, the natural gas distributor collects the hydrocarbon royalty on behalf of the provincial government through a green fund contribution charge on gas consumed. In 2010, 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.

The carbon tax in B.C., which came into effect in mid-2008, applies to CO_2 emissions 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 2010 were estimated at $4 million. As specified by this law, the cost per tonne of CO_2 will increase in July 2011 to $25.00 from $20.00.

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 in January 2009. Under the RGGI, both the Ravenswood and Ocean State Power generation facilities will be required to submit allowances following the end of the first compliance period on December 31, 2011. TransCanada participated in the quarterly auctions of allowances for the Ravenswood and Ocean State Power generation facilities and incurred related costs of approximately $5 million in 2010. These costs were generally recovered through the power market and the net impact on TransCanada was not significant.

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RISK FACTORS

Environmental Risk Factors

Environmental Risks

Environmental risks from TransCanada s operating facilities typically include: air emissions, such as nitrogen oxides, particulate matter and GHGs; potential impacts on land, including land reclamation or restoration following construction; the use, storage and 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.

As mentioned above, TransCanada 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, and with damage claims arising from the contamination of properties. It is not possible for TransCanada 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 the Company s 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 of them; and
- the potential for litigation on existing or discontinued assets.

Oil Leaks and Spills

In 2010, the Wood River/Patoka phase of Keystone became operational. Steel pipelines are a safe, efficient and economical method of transporting crude oil. The equipment and procedures put in place with respect to Keystone provide the capability to contain oil leaks quickly and safely.

TransCanada s pipelines are designed, constructed and operated to the highest industry standards and meet or exceed all regulatory requirements. Keystone is continuously monitored and is fully automated with remotely started secure pumps and valves. A variety of methods are used to detect and prevent leaks. In the unlikely event of a leak or spill, valves can be closed to isolate the leak and limit spill volumes.

The Company has established emergency response plans to be enacted in the unlikely event of a leak or spill along TransCanada s operational crude oil pipeline. The plans encompass the necessary personnel and equipment to respond to any size of spill as well as clean-up and remediation operations to minimize any effects on the environment. The plan outlines specific environmental features in the vicinity of the pipeline and containment and remediation efforts are based on practices that are well-understood and tested. In addition, TransCanada has an on-going program to provide local emergency responders with the information and training necessary to ensure their preparedness for responding to events.

Changing Legislation and Regulations

The impact of new or proposed provincial, state and/or federal safety and environmental laws, regulations, guidelines and enforcement in Canada and the U.S. on TransCanada s business is not yet certain. TransCanada makes assumptions about possible expenditures to safety and environmental matters based on current laws and regulations and interpretations thereof. If the laws or regulations or the interpretation thereof changes, the Company s assumptions may change. Incremental costs may or may not be recoverable under existing rate structures or commercial agreements. Proposed changes in environmental policy, legislation or regulation are routinely monitored by TransCanada, and where the risks are potentially large or uncertain, the Company works independently or through industry associations to comment on proposals.

In April 2010, the Environmental Protection Agency (EPA) published an Advanced Notice of Proposed Rulemaking to solicit comments with respect to EPA s reassessment of current regulations under the *Toxic Substances Control Act*, governing the authorized use of polychlorinated biphenyls (PCBs) in certain equipment. The proposed changes could require notification to the EPA when PCBs are discovered in any pipeline system, a phase out and eventual elimination of PCB use in pipeline systems and air compressor systems and the immediate elimination of the storage of PCB equipment for reuse. If finalized as proposed, these changes are likely to have significant cost implications for the Company s U.S. assets.

Regulation of air pollutant emissions under the U.S. *Clean Air Act* (CAA) and state regulations continue to evolve. A number of EPA initiatives could lead to impacts ranging from requirements to install emissions control equipment, to additional administrative and reporting requirements. At this time, there is insufficient detail to accurately determine the potential impacts of these initiatives. While the majority of the proposals are not expected to be material to TransCanada, the Company anticipates additional future costs related to the monitoring and control of air emissions.

In addition to those climate change policies already in force, 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 policies, TransCanada anticipates that most of the Company s facilities in Canada and the U.S. are or will be subject to federal and/or regional climate change regulations to manage industrial GHG emissions. Certain of these 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 submitted a revised GHG reduction target to the United Nations Framework Convention on Climate Change as part of its submission for the Copenhagen Accord. The revised target represents a 17 per cent reduction in GHG emissions by 2020 relative to 2005 levels. In June 2010, the Federal government initiated consultation on its policy for coal-fired power operations with the stated intention of publishing the draft regulatory framework in *Canada Gazette* in early 2011. TransCanada participated in this consultation process directly through meetings with government officials and through the Canadian Electricity Association. The new regulations to reduce GHG emissions for coal-fired operations are expected to come into effect in July 2015.

In the U.S., the EPA is proceeding towards regulating industrial GHG emissions under the CAA. In May 2010, the EPA issued its final version of the Tailoring Rule which outlines emissions thresholds and a schedule for phasing in certain permitting requirements under the CAA. Under this rule, the Prevention of Significant Deterioration program stipulates the air pollution protection criteria a company must meet to obtain a construction permit. Requirements will apply to GHG emissions starting in January 2011. The second phase of the program will commence in July 2011, with new rulemaking in 2012 to establish emission thresholds and permitting requirements to take effect in 2013. In addition to the Prevention of Significant Deterioration requirements, the Tailoring Rule sets comparable emissions thresholds and timetables for new and existing facilities to obtain operating permits under Title V of the CAA. The regulation of GHG emissions by the EPA under the CAA would have implications for TransCanada with respect to permitting for existing, new and modified facilities.

The Western Climate Initiative (WCI) continues to work toward implementing a regional cap-and-trade program expected to come into effect in 2012. The cap-and-trade program would be a key component of the plan to help WCI members reach their goal of reducing GHG emissions 15 per cent below 2005 by 2020. Beginning in 2012, the cap would cover utilities and large industrial sectors, and expand by 2015 to cover transportation fuels, and commercial and residential fuels. The WCI comprises seven Western states and four Canadian provinces. While TransCanada has assets located in all four Canadian member provinces (B.C., Manitoba, Ontario and Québec) and five of the member states (California, Oregon, Washington, Montana and Arizona), the cap-and-trade program is proposed to begin in 2012 in California and the Canadian provinces of B.C., Québec, and Ontario. The programs would cover TransCanada s pipeline and power facilities, however, TransCanada expects the cost of compliance would be largely recoverable on the facilities that trigger emissions thresholds.

TransCanada 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.

With respect to business opportunities, the Company has well established processes and criteria for assessing new business opportunities including those that may arise as a result of climate change policies. These processes have been and continue to be key contributors to TransCanada s financial strength and success. Governments in North America are developing long-term plans for limiting GHG emissions. These plans, combined with a shift in consumer attitude and demand for low-emissions fuels, will require changes in energy supply and infrastructure. With the Company s experience in pipeline transmission and power generation, TransCanada is well-positioned to participate in these opportunities.

With respect to physical risks arising from climate change, TransCanada has in place a set of procedures to manage its response to natural disasters such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes regardless of cause. These procedures are included in TransCanada s Operating Procedures and are part of the Company s Incident Management System. The procedures ensure that the health and safety of the Company s employees and the environment are not compromised during natural disasters.

TransCanada s assets are located throughout North America and the Company s facility design must deal with different geographical areas. In northern regions, changing permafrost levels due to warmer temperatures have been experienced, however, very few kilometers of TransCanada s pipeline systems are currently in permafrost regions. If TransCanada builds new facilities in northern areas, the Company s facility designs will take into account the potential for changing permafrost levels.

Other Risk Factors

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

DIVIDENDS

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

Holders of cumulative redeemable first preferred shares, series 1 (Series 1 Preferred Shares) are entitled to receive fixed cumulative dividends, at an annual rate of $1.15 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending December 31, 2014. For the period from issuance on September 30, 2009 to December 31, 2009, dividends in the amount of $0.2899 per share were declared and paid on the Series 1 Preferred Shares. For the period January 1, 2010 to December 31, 2010, dividends in the amount of $1.15 per share were declared and paid on the Series 1 Preferred Shares. The dividend on the Series 1 Preferred Shares will reset on December 31, 2014 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.92 per cent. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 2 (the Series 2 Preferred Shares) as set out under the heading First Preferred Shares below.

Holders of cumulative redeemable first preferred shares, series 3 (Series 3 Preferred Shares) are entitled to receive fixed cumulative dividends, at an annual rate of $1.00 per share, payable quarterly, as and when declared by the Board, for the initial five year period ending June 30, 2015. For the period from issuance on March 12, 2010 to December 31, 2010, dividends in the amount of $0.8041 per share were declared and paid on the Series 3 Preferred Shares. The dividend on the Series 3 Preferred Shares will reset on June 30, 2015 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.28 per cent. The holders of Series 3 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 4 (the Series 4 Preferred Shares) as set out under the heading First Preferred Shares below.

Holders of cumulative redeemable first preferred shares, series 5 (Series 5 Preferred Shares) are entitled to receive fixed cumulative dividends, at an annual rate of $1.10 per share, payable quarterly, as and when declared by the Board, for the initial five and a half year period ending January 30, 2016. For the period from issuance on June 29, 2010 to December 31, 2010, dividends in the amount of $0.6457 per share were declared and dividends in the amount of $0.3707 per share were paid, on the Series 5 Preferred Shares. The dividend on the Series 5 Preferred Shares will reset on January 30, 2016 and every five years thereafter to a rate equal to the sum of the then five year Government of Canada bond yield and 1.54 per cent. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable first preferred shares, series 6 (the Series 6 Preferred Shares) as set out under the heading First Preferred Shares below.

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

	2010	2009	2008
Dividends declared on Common Shares	$1.60	$1.52	$1.44

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

TransCanada s authorized share capital consists of an unlimited number of Common Shares, of which 696,229,462 were issued and outstanding at Year End, and an unlimited number of first preferred shares and second preferred shares, issuable in series, of which 22 million Series 1 Preferred Shares, 14 million Series 3 Preferred Shares and 14 million Series 5 Preferred Shares are issued and outstanding. The following is a description of the material characteristics of each of these classes of shares.

Common Shares

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

TransCanada has a Shareholder Rights Plan (the SR Plan) that is designed to ensure, to the extent possible, that all shareholders of TransCanada are treated fairly in connection with any take-over bid for the Company. The SR Plan creates a right attaching to each Common Share outstanding and to each Common Share subsequently issued. Each right becomes exercisable ten trading days after a person has acquired, or commences a take-over bid to acquire, 20 per cent or more of the Common Shares, other than by an acquisition pursuant to a take-over bid permitted under the terms of the SR Plan. Prior to a flip-in event (as described below), each right permits registered holders to purchase from the Company Common Shares of TransCanada at the exercise price equal to three times the market price of such shares, subject to adjustments and anti-dilution provisions (the Exercise Price). The beneficial acquisition by any person of 20 percent or more of the Common Shares, other than by way of a take-over bid permitted under the terms of the SR Plan, is referred to as a Flip-in Event . Ten trading days after a Flip-in Event, each TransCanada right will permit registered holders to receive, upon payment of the exercise price, the number of Common Shares with an aggregate market price equal to twice the exercise price. The SR Plan was reconfirmed at the 2010 annual and special meeting of shareholders and must be reconfirmed every third annual meeting thereafter.

TransCanada has a Dividend Reinvestment and Share Purchase Plan which permits common and preferred shareholders of TransCanada and preferred shareholders of TCPL, to elect to reinvest their cash dividends in additional Common Shares of TransCanada. These Common Shares may be provided to the participants at a discount to the average market price in the five days before dividend payment. The discount was set at three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. The discount was set at two per cent for 2008 and was increased to three per cent commencing with the dividend declared in February 2009. Participants may also make additional cash payments of up to $10,000 per quarter to purchase additional Common Shares, which optional purchases are not eligible for any discount on the price of Common Shares. Participants are not responsible for payment of brokerage commissions or other transaction expenses for purchases made pursuant to the Dividend Reinvestment and Share Purchase Plan.

TransCanada also has stock-based compensation plans (the SOPs) that allow some employees to purchase Common Shares of TransCanada. Option exercise prices approximate the market price for the Common Shares on the date the options were issued. Options granted under the SOPs are generally fully exercisable after three years and expire seven years after the date of grant.

First Preferred Shares

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

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

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

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

The Series 1 Preferred Shares are entitled to the payment of dividends as set out above under the heading Dividends . The Series 1 Preferred Shares are redeemable by TransCanada in whole or in part on or after December 31, 2014, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 1 Preferred Shares have the right to convert their shares into cumulative redeemable Series 2 Preferred Shares, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 1.92 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 1 Preferred Shares shall be entitled to receive $25.00 per Series 1 Preferred Share plus all accrued and unpaid dividends thereon in preference over the Common Shares or any other shares ranking junior to the Series 1 Preferred Shares.

The Series 3 Preferred Shares are entitled to the payment of dividends as set out above under the heading Dividends . The rights, privileges, restrictions and conditions attaching to the Series 3 Preferred Shares are substantially identical to those attaching to the first preferred shares, except as outlined below. The Series 3 Preferred Shares are redeemable by TransCanada in whole or in part on or after June 30, 2015, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 3 Preferred Shares have the right to convert their shares into cumulative redeemable Series 4 Preferred Shares, subject to certain conditions, on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 1.28 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 3 Preferred Shares shall be entitled to receive $25.00 per Series 3 Preferred Share plus all accrued and unpaid dividends thereon in preference over the Common Shares or any other shares ranking junior to the Series 3 Preferred Shares.

The Series 5 Preferred Shares are entitled to the payment of dividends as set out above under the heading Dividends . The rights, privileges, restrictions and conditions attaching to the Series 5 Preferred Shares are substantially identical to those attaching to the first preferred shares, except as outlined below. The Series 5 Preferred Shares are redeemable by TransCanada in whole or in part on or after January 30, 2016, by the payment of an amount in cash for each share to be redeemed equal to $25.00 plus all accrued and unpaid dividends thereon. The holders of Series 5 Preferred Shares have the right to convert their shares into cumulative redeemable Series 6 Preferred Shares, subject to certain conditions, on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 Preferred Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the Board, at a rate equal to the sum of the then 90-day Government of Canada treasury bill rate plus 1.54 per cent. In the event of liquidation, dissolution or winding up of TransCanada, the holders of Series 5 Preferred Shares shall be entitled to receive $25.00 per Series 5 Preferred Share plus all accrued and unpaid dividends thereon in preference over the Common Shares or any other shares ranking junior to the Series 5 Preferred Shares.

Except as provided by the CBCA, the respective holders of the Series 1, 2, 3, 4, 5 and 6 Preferred Shares are not entitled to receive notice of, attend at, or vote at any meeting of shareholders unless and until TransCanada shall have failed to pay eight quarterly dividends, whether or not consecutive, in which case the respective holders of Series 1, 2, 3, 4, 5 and 6 Preferred Shares shall have the right to receive notice of and to attend each meeting of shareholders at which directors are to be elected and which take place more than 60 days after the date on which the failure first occurs, and to one vote with respect to resolutions to elect directors for each Series 1, 2, 3, 4, 5 and 6 Preferred Share, respectively, until all arrears of dividends have been paid.

Second Preferred Shares

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

CREDIT RATINGS

Although TransCanada has not issued debt to the public, it has been assigned credit ratings by Moody s Investors Service, Inc. (Moody s) and Standard and Poor s (S&P). Moody s has assigned an issuer rating of Baa1 with a stable outlook and S&P has assigned a long-term corporate credit rating of A- with a stable outlook TransCanada does not presently intend to issue debt securities to the public in its own name and any future debt financing requirements are expected to continue to be funded primarily through its subsidiary, TCPL. The following table sets out the current credit ratings assigned to those outstanding classes of securities of TCPL which have been rated by DBRS Limited (DBRS), Moody s and 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.

The following information concerning the Company s credit ratings relates to the Company s financing costs, liquidity and operations. The availability of TransCanada s funding options may be affected by certain factors, including the global capital market environment and outlook as well as the Company s financial performance. TransCanada s access to capital markets at competitive rates is dependent on its credit rating and rating outlook, as determined by credit rating agencies such as DBRS, Moody s and S&P, and if TransCanada s ratings were downgraded the Company s financing costs and future debt issuances could be unfavorably impacted. 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 all rating categories other than AAA and D. 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 good credit quality. The overall strength is not as favourable as higher rating categories, but any qualifying negative factors that exist are considered manageable. 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 good credit quality. The capacity for the payment of interest and principal is substantial, but the degree of strength is less than that of AA rated securities. 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. The capacity for the payment of interest and principal is considered acceptable, but it may be vulnerable to future events. 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. In general, Pfd-2 ratings correspond with long-term debt rated in the A category.

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 from Aa through Caa, with 1 being the highest and 3 being the lowest. The A3 rating assigned to TCPL s senior unsecured debt is in the third highest of nine rating categories for long-term obligations. Obligations rated A are

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considered upper medium grade and are subject to low credit risk. The Baa1 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 from AA through CCC 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 s Common Shares are listed on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol TRP . TransCanada s Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 Preferred Shares have been listed for trading on the TSX since September 30, 2009, March 12, 2010 and June 29, 2010, respectively under the symbols TRP.PR.A , TRP.PR.B , and TRP.PR.C , respectively. 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 respective Series 1 Preferred Shares, Series 3 Preferred Shares and Series 5 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 2010	38.71	36.53	37.99	36,564,145	38.44	35.86	38.04	8,743,709
November 2010	38.04	35.49	36.20	47,122,180	37.72	34.77	35.33	8,000,248
October 2010	39.28	37.06	37.67	24,452,953	38.59	36.33	36.95	6,887,287
September 2010	38.88	37.25	38.17	35,287,579	37.75	36.00	37.12	5,548,775
August 2010	38.45	35.75	38.00	23,551,406	36.53	34.23	35.64	6,079,595
July 2010	37.25	35.50	36.33	30,315,925	35.85	32.86	35.35	8,077,360
June 2010	37.31	34.57	35.61	30,159,655	36.69	33.02	33.43	8,154,916
May 2010	36.92	30.01	35.50	32,936,332	36.47	25.80	33.17	9,235,485
April 2010	38.16	35.18	35.84	30,450,870	38.01	34.92	35.20	6,424,836
March 2010	37.87	34.75	37.22	42,951,844	37.11	33.20	36.76	5,806,751
February 2010	35.30	33.96	34.78	25,627,521	33.68	31.58	33.00	5,669,857
January 2010	36.44	34.00	34.17	23,180,090	35.07	31.85	31.91	6,314,623

Series 1 Preferred Shares

	TSX (TRP.PR.A)			
Month	High ($)	Low ($)	Close ($)	Volume Traded
December 2010	26.00	25.50	26.00	559,051
November 2010	26.79	25.95	25.97	583,072
October 2010	26.45	26.13	26.29	528,964
September 2010	27.89	25.90	26.24	613,195
August 2010	26.11	25.80	26.00	623,916
July 2010	25.95	25.35	25.95	454,853
June 2010	25.90	25.15	25.45	552,510
May 2010	25.45	25.00	25.11	1,147,115
April 2010	25.85	25.06	25.25	619,658
March 2010	26.59	25.08	25.69	1,289,162
February 2010	26.29	25.80	25.95	727,716
January 2010	27.15	25.80	26.15	1,561,414

Series 3 Preferred Shares

	TSX (TRP.PR.B)			
Month	High ($)	Low ($)	Close ($)	Volume Traded
December 2010	25.59	24.65	25.57	219,795
November 2010	25.98	24.85	24.98	342,225
October 2010	25.48	24.85	25.10	522,319
September 2010	25.66	24.95	25.36	431,061
August 2010	25.20	24.85	24.98	533,912
July 2010	25.00	24.60	24.94	291,835
June 2010	24.75	24.16	24.65	425,787
May 2010	24.84	23.99	24.20	458,273
April 2010	25.07	23.90	23.90	497,079
March 2010	25.08	24.83	25.02	1,817,221

Series 5 Preferred Shares

	TSX (TRP.PR.C)			
Month	High ($)	Low ($)	Close ($)	Volume Traded
December 2010	26.26	25.00	25.81	351,359
November 2010	26.45	25.50	25.65	397,725
October 2010	26.17	25.36	25.56	499,857
September 2010	26.50	25.28	25.69	597,352
August 2010	25.82	25.20	25.70	613,671

July 2010	25.41	24.84	25.30	1,084,450
June 2010	24.98	24.75	24.95	944,707

In addition, TransCanada s subsidiary, TCPL, has cumulative redeemable first preferred shares, series U and series Y listed on the TSX under the symbols TCA.PR.X , and TCA.PR.Y , respectively.

DIRECTORS AND OFFICERS

As of February 14, 2011, the directors and officers of TransCanada as a group beneficially owned, or exercised control or direction, directly or indirectly, over an aggregate of 517,667, 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 TransCanada and its significant affiliates, their principal occupations or employment during the past five years and the year from which each director has continually served as a director of TransCanada and, prior to the arrangement, with TCPL. Positions and offices held with TransCanada are also held by such person at TCPL. 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 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(1), O.C. Ottawa, Ontario Canada	Senior strategic advisor at Ogilvy Renault LLP (law firm). Chair (not a Director), International Advisory Board for Garda World Consulting & Investigation, a division of Garda World Security Corporation since 2008. Chair, Canwest Global Communications Corp. (communications) from August 2006 (director since April 2005) to October 2010 and 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. Director, Institute for International Business, University of Toronto and Director, the Toronto-Dominion Bank. Vice Chair, 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 U.S.	Director, Alliance Data Systems Corporation (data processing and services) and Director, Alpha Natural Resources, Inc. (mining). Chair, NorthWestern Corporation (conducting business as NorthWestern Energy) (oil and gas). Lead Director, 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, Royal Bank of Canada and Care Canada. Director, Institut Québecois des Hautes Études Internationales, Laval University from 2002 until 2009.	2002
Russell K. Girling Calgary, Alberta Canada	President and Chief Executive Officer, TransCanada since July 1, 2010. Chief Operating Officer from July 2009 to June 30, 2010 and President, Pipelines from June 2006 to June 30, 2010. Prior to June 2006, Chief Financial Officer and Executive Vice-President, Corporate Development. Director, Agrium Inc.	2010
Kerry L. Hawkins	Director, NOVA Chemicals Corporation until July 2009. President, Cargill Limited (agricultural) from September 1982 to December 2005.	1996

Winnipeg, Manitoba Canada		
S. Barry Jackson Calgary, Alberta Canada	Chair of the Board, TransCanada since April 2005. Director, Nexen Inc. (oil and gas) and Director, WestJet Airlines Ltd. Chair, Resolute Energy Inc. (oil and gas) from January 2002 to April 2005. Chair of Deer Creek Energy Limited (oil and gas) from April 2001 to September 2005.	2002
Paul L. Joskow New York, New York U.S.	Economist and President of the Alfred P. Sloan Foundation. Professor of Economics, Emeritus, 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, Exelon Corporation (energy), and a trustee of Putnam Mutual Funds.	2004
John A. MacNaughton(2), C.M. Toronto, Ontario Canada	Chair of the Business Development Bank of Canada. Chair, CNSX Markets Inc. (formerly the Canadian Trading and Quotation System Inc.) (stock exchange) from 2006 to July 2010. Director, Nortel Networks Corporation and Nortel Networks Limited (the principal operating subsidiary of Nortel Networks Corporation) (technology) from 2005 to September 2010. Chair of the Independent Nominating Committee of the 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

Name and Place of Residence	Principal Occupation During the Five Preceding Years	Director Since
David P. O Brien(3) 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, and Enerplus Corporation. Member of the Science, Technology and Innovation Council of Canada.	2001
W. Thomas Stephens Greenwood Village, Colorado U.S.	Chair and Chief Executive Officer of Boise Cascade, LLC from November 2004 to November 2008. Director, Boise Inc. until April 2010. Trustee, Putnam Mutual Funds.	2007(4)
D. Michael G. Stewart Calgary, Alberta Canada	Director, Canadian Energy Services & Technology Corp. (previously Canadian Energy Services LP (Director, Canadian Energy Services Inc., the GP)), Pengrowth Energy Corporation (previously Pengrowth Corporation (the administrator of Pengrowth Energy Trust)) and C&C Energia Ltd. Director, Orleans Energy Ltd. from October 2008 to December 2010. Chairman and a trustee of Esprit Energy Trust (oil and gas) from August 2004 to October 2006. Director, 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) 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* (CCAA) on October 6, 2009. Although no cease trade orders were issued, following the filing Canwest shares were de-listed from trading on the TSX and now trade on the TSX Venture Exchange. Canwest emerged from CCAA protection and its newspaper business was acquired by Postmedia Network on July 13, 2010 and its broadcast media business was acquired by Shaw Communications Inc. on October 27, 2010. Mr. Burney ceased to be a director of Canwest on October 27, 2010.

(2) 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 CCAA.

(3) Air Canada filed for protection under the CCAA and applicable bankruptcy protection statutes in the U.S. in April 2003. Mr. O Brien resigned as a director of Air Canada on November 26, 2003.

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

Board Committees

TransCanada 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 and 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 and 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 TransCanada reside in Calgary, Alberta, Canada, with the exception of Mr. Hobbs who resides in Houston, Texas, U.S. References to positions and offices with TransCanada prior to May 15, 2003 are references to the positions and offices held with TCPL. Current positions and offices held with TransCanada are also held by such person at TCPL. As of the date hereof, the officers of TransCanada, their present positions within TransCanada and their principal occupations during the five preceding years are as follows:

Executive Officers

Name	**Present Position Held**	**Principal Occupation During the Five Preceding Years**
Russell K. Girling	President and Chief Executive Officer	Prior to July 2010, Chief Operating Officer since July 2009 and President, Pipelines since June 2006. Prior to June 2006, Executive Vice-President, Corporate Development, since March 2003 and Chief Financial Officer, since August 1999.
Gregory A. Lohnes	Executive Vice-President and President, Natural Gas Pipelines	Prior to July 2010, Executive Vice-President and Chief Financial Officer. Prior to June 2006, President and Chief Executive Officer of Great Lakes Gas Transmission Company, since August 2000.
Donald R. Marchand	Executive Vice-President and Chief Financial Officer	Prior to July 2010, Vice-President, Finance and Treasurer, since September 1999.
Dennis J. McConaghy	Executive Vice-President, Corporate Development	Prior to July 2010, Executive Vice-President, Pipeline Strategy and Development. Prior to June 2006, Executive Vice-President, Gas Development, since May 2001.
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 2006. Prior to June 2006, Vice-President, Transactions, Power Division, TCPL, since April 2003.
Alexander J. Pourbaix	President, Energy and Oil Pipelines	President, Energy from June 2006 to June 2010 and Executive Vice-President, Corporate Development from July 2009 to June 2010. Prior to June 2006, Executive Vice-President, Power, since March 2003.
Sarah E. Raiss	Executive Vice-President, Corporate Services	Executive Vice-President, Corporate Services, since January 2002.
Donald M. Wishart	Executive Vice-President, Operations and Major Projects	Prior to July 2009, Executive Vice-President, Operations and Engineering, since March 2003.

Corporate Officers

Name	Present Position Held	Principal Occupation During the Five Preceding Years
Sean M. Brett	Vice-President and Treasurer	Prior to July 2010, Vice-President, Commercial Operations of TC Pipelines GP, Inc., and Director, LP Operations of TCPL. Prior to November 2009, Director, Joint Venture Management, Keystone Pipeline Project of TCPL. Prior to December 2008, Vice-President and Treasurer of TC Pipelines GP, Inc. Prior to January 2007, Mr. Brett held a number of positions of increasing responsibility with TransCanada s Finance and Treasury Group.
Ronald L. Cook	Vice-President, Taxation	Vice-President, Taxation, since April 2002.
Donald J. DeGrandis	Vice-President and Corporate Secretary	Prior to February 2009, Corporate Secretary. Prior to June 2006, Associate General Counsel, Corporate Services, since June 2004.

Lee G. Hobbs	President, U.S. Natural Gas Pipelines	Senior Vice-President and General Manager, U.S. Pipelines, Pipelines Division, TCPL, June 2009 to July 2010. Vice-President and General Manager, U.S. Pipelines Central, Pipelines Division, TCPL, March 2007 to June 2009. President, Great Lakes Gas Transmission Company and Great Lakes Gas Transmission Limited Partnership, September 2006 to March 2007. Prior to September 2006, Vice-President and Controller, TCPL, since July 2001.
Joel E. Hunter	Vice-President, Finance	Director, Corporate Finance, January 2008 to July 2010. Prior to January 2008, Senior Analyst, Corporate Finance. Prior to January 2007 Mr. Hunter held a number of positions of increasing responsibility with TransCanada s Finance and Treasury Group.
Garry E. Lamb	Vice-President, Risk Management	Vice-President, Risk Management, since October 2001.
G. Glenn Menuz	Vice-President and Controller	Prior to June 2006, Assistant Controller, since October 2001.

Conflicts of Interest

Directors and officers of TransCanada and its subsidiaries are required to disclose the existence of existing or potential conflicts in accordance with TransCanada policies governing directors and officers and in accordance with the CBCA. Although some of the directors sit on boards or may be otherwise associated with companies that ship natural gas on TransCanada s pipeline systems, TransCanada, 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, TransCanada 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 TransCanada s management are committed to the highest standards of corporate governance. TransCanada s corporate governance practices comply with the governance rules of the CSA, those of the NYSE and of the SEC applicable to foreign issuers. As a non-U.S. company, TransCanada is not required to comply with most of the NYSE corporate governance listing standards; however, except as summarized on 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. TransCanada is in compliance with the CSA s National Instrument 52-110, Audit Committees; National Policy 58-201, Corporate Governance Guidelines; and National Instrument 58-101, Disclosure of Corporate Governance Practices. Further information about TransCanada s corporate governance can be found on TransCanada s website at www.transcanada.com under the heading Corporate Governance or at Schedule B to TransCanada s Management Proxy Circular dated February 14, 2011.

AUDIT COMMITTEE

TransCanada has an Audit Committee which is responsible for assisting the Board in overseeing the integrity of TransCanada s financial statements and compliance with legal and regulatory requirements and in ensuring the independence and performance of TransCanada s internal and external auditors. The Charter of the Audit Committee can be found in Schedule B of this AIF and on TransCanada s website under the Corporate Governance Board Committees page, at 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 TransCanada, of each member of the Audit Committee that is relevant to the performance of his 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 The Insurance Corporation of British Columbia 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 Chair and Chief Executive Officer of Bell Canada International Inc. Mr. Burney was the lead director at Shell Canada Limited until May 2007 and was the Chair of Canwest Global Communications Corp. until October 2010. 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 Chair, President and Chief Executive Officer of American Electric Power Co., Inc. until 2004. He previously served as Chair, 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 a Professor of Economics, Emeritus, at 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 Chair of the Business Development Bank of Canada, and was Chair of CNSX Markets Inc. (formerly Canadian Trading and Quotation System Inc.) until July 2010. 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 37 years.

Pre-Approval Policies and Procedures

TransCanada s Audit Committee has adopted a pre-approval policy with respect to permitted non-audit services. Under the policy, the Audit Committee has granted pre-approval for specified non-audit services. For engagements of $25,000 or less which are not within the annual pre-approved limit, approval by the Audit Committee is not required, and for engagements between $25,000 and $100,000, approval of the Audit Committee Chair is required, and 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, TransCanada 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 2010 and 2009 fiscal years.

Fee Category	2010	2009	Description of Fee Category
	(millions of dollars)		
Audit Fees	**$6.5**	**$7.2**	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	**$0.2**	**$0.2**	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 Company pension plans.
Tax Fees	**$1.0**	**$1.1**	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	**$0.2**	**$0.4**	Aggregate fees for products and services other than those reported elsewhere in this table. The nature of these services primarily consisted of advice and training primarily related to IFRS.
Total	**$7.9**	**$8.9**	

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

TransCanada 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 TransCanada s favour, it is the opinion of TransCanada 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.

TRANSFER AGENT AND REGISTRAR

TransCanada 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

TransCanada 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 TransCanada may be found under TransCanada s profile on SEDAR at www.sedar.com.

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

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

GLOSSARY

AcSB	Accounting Standards Board
AGIA	*Alaska Gasline Inducement Act*
AIF	Annual Information Form of TransCanada Corporation dated February 14, 2011
Alaska Pipeline	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 and Northeast B.C.
ANR	American Natural Resources Company and ANR Storage Company, collectively
ANR System	A natural gas transmission system extending from producing fields located primarily in Texas, Oklahoma, the Gulf of Mexico and U.S. Midcontinent region to markets located primarily in Wisconsin, Michigan, Illinois, Ohio and Indiana, and regulated underground natural gas storage facilities in Michigan
AUC	Alberta Utilities Commission
Bakken Marketlink	A proposed pipeline that would transport crude oil from Baker, Montana to Cushing on facilities that form part of the U.S. Gulf Coast Expansion
Bbl/d	Barrels per day
B.C.	British Columbia
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
Bécancour	A natural gas-fired cogeneration plant near Trois-Rivières, Québec
Bison	A natural gas pipeline extending from the Powder River Basin in Wyoming to the NBPL System in North Dakota
Board	TransCanada s Board of Directors
Bruce A	A partnership interest in a nuclear power generation facility consisting of Units 1 to 4 of Bruce Power (Bruce Power A L.P.)
Bruce B	A partnership interest in a nuclear power generation facility consisting of Units 5 to 8 of Bruce Power (Bruce Power L.P.)
Bruce Power	A nuclear power generating facility located northwest of Toronto, Ontario (Bruce A and Bruce B, collectively)
CAA	*Clean Air Act*
Canadian GAAP	Canadian generally accepted accounting principles
Canadian Mainline	A natural gas transmission system extending from the Alberta/Saskatchewan border east into Québec
Canwest	Canwest Global Communications Corp.
Cartier Wind	Five wind farms in Gaspé, Québec, three of which are operational and two under construction
CBCA	*Canada Business Corporations Act*
CCAA	*Companies Creditors Arrangement Act*
Chinook	A proposed power transmission line project originating in Montana and terminating in Nevada
CICA	Canadian Institute of Chartered Accountants
CO2	Carbon dioxide
Common Shares	Common shares of TransCanada
Coolidge	A simple-cycle, natural gas-fired peaking power generation station under construction in Coolidge, Arizona
CSA	Canadian Securities Administrators
Cushing Extension	The second phase of the Keystone oil pipeline delivering crude oil to Cushing, Oklahoma
Cushing Marketlink	A proposed pipeline that would provide crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the U.S. Gulf Coast Expansion
DBRS	DBRS Limited
Energy	As defined in this AIF under the heading General Development of the Business
EPA	Environmental Protection Agency (U.S.)

Exercise Price	As defined in this AIF under the heading Description of Capital Structure
ExxonMobil	ExxonMobil Corporation
FERC	Federal Energy Regulatory Commission (U.S.)
Foothills System	A natural gas transmission system extending from central Alberta to the B.C./U.S. border and to the Saskatchewan/U.S. border
GHG	Greenhouse gas
Great Lakes	Great Lakes Gas Transmission Limited Partnership
Great Lakes System	A natural gas transmission system that connects to the Canadian Mainline and serves markets in Eastern Canada and the Northeastern and Midwestern U.S.
Groundbirch	A phase of the Alberta System, connecting natural gas supply primarily from the Montney shale gas formation in Northeast B.C. to existing infrastructure in Northwest Alberta
GTN System	A natural gas transmission system extending from the B.C./Idaho border to the Oregon/California border, traversing Idaho, Washington and Oregon
Guadalajara	A natural gas pipeline under construction in Mexico extending from Manzanillo, Colima to Guadalajara, Jalisco
Halton Hills	A natural gas-fired, combined cycle power plant in Halton Hills, Ontario
Horn River	A proposed extension of the Alberta System that would connect new shale gas supply in the Horn River basin north of Fort Nelson, B.C.
HS&E	Health, safety and environment
HVDC	High voltage direct current
Hydro-Québec	Hydro-Québec Distribution
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
Iroquois System	A natural gas transmission system connects with the Canadian Mainline near Waddington, New York and delivers natural gas in the Northeastern U.S.
ISO	International Organization for Standardization
Keystone Canada	TransCanada Keystone Pipeline Limited Partnership

Keystone	Wood River/Patoka, the Cushing Extension and the U.S. Gulf Coast Expansion, collectively
Keystone U.S.	TransCanada Keystone Pipeline, LP
Kibby Wind	A wind farm located in Kibby and Skinner townships in northwestern Franklin County, Maine
km	Kilometer(s)
LNG	Liquefied Natural Gas
Mackenzie Gas Project	A proposed natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta
MD&A	TransCanada s Management s Discussion and Analysis dated February 14, 2011
MIT	Massachusetts Institute of Technology
MMcf/d	Million cubic feet per day
Moody s	Moody s Investors Service, Inc.
MW	Megawatt(s)
Natural Gas Pipelines	As defined in this AIF under the heading General Development of the Business
NBPL	Northern Border Pipeline Company
NBPL System	A natural gas transmission system extending from a point near Monchy, Saskatchewan to the U.S. Midwest
NEB	National Energy Board
Nortel	Nortel Networks Limited and Nortel Networks Corporation
North Baja System	A natural gas transmission system extending from Arizona to the Baja California, Mexico/California border
North Central Corridor	A phase of the Alberta System which extends the northern section thereof
NYSE	New York Stock Exchange
Ocean State Power	A natural gas-fired, combined-cycle plant in Burrillville, Rhode Island
Oil Pipelines	As defined in this AIF under the heading General Development of the Business
OPA	Ontario Power Authority
OSC	Ontario Securities Commission
PCBs	Polychlorinated biphenyls
Portland System	A natural gas transmission system that extends from a point near East Hereford, Québec to the Northeastern U.S.
Portlands Energy	A natural gas-fired combined-cycle power plant near downtown Toronto, Ontario
Ravenswood	A natural gas-and oil-fired generating facility located in Queens, New York
RGGI	Regional Greenhouse Gas Initiative
RRA	Rate-regulated accounting
S&P	Standard and Poor s
SEC	U.S. Securities and Exchange Commission
Series 1 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 1
Series 2 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 2
Series 3 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 3
Series 4 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 4
Series 5 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 5
Series 6 Preferred Shares	TransCanada s cumulative, redeemable, first preferred shares, series 6
Sheerness	A coal-fired power generating facility near Hanna, Alberta
SOPs	TransCanada s stock-based compensation plans
SR Plan	TransCanada s Shareholder Rights Plan
Subsidiary	As defined in this AIF under the heading Presentation of Information
Sundance	Two coal-fired power generating facilities near Wabamun, Alberta (Sundance A and Sundance B, collectively)
Systems	As defined in this AIF under the heading Regulation of the Pipeline Business
TCPL	TransCanada PipeLines Limited
TQM	A natural gas pipeline that connects with the Canadian Mainline near the Québec/Ontario border and transports natural gas to markets in Québec, and connects with the Portland System
TransCanada or the Company	TransCanada Corporation
TransAlta	TransAlta Corporation
TSX	Toronto Stock Exchange
Tuscarora	Tuscarora Gas Transmission Company
Tuscarora System	A natural gas transmission system extending from Malin, Oregon to Wadsworth, Nevada
U.S. or US	United States
U.S. GAAP	U.S. generally accepted accounting principles
U.S. Gulf Coast Expansion	A proposed extension and expansion of the Keystone crude oil pipeline to the U.S. Gulf Coast
WCI	Western Climate Initiative
Wood River/Patoka	The first phase of the Keystone oil pipeline delivering crude oil to Wood River and Patoka in Illinois
Year End	December 31, 2010
Zephyr	A proposed power transmission line project originating in Wyoming and terminating in Nevada

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

CHARTER OF THE AUDIT COMMITTEE

1. Purpose

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

- Company s financial accounting and reporting process;
- integrity of the financial statements
- Company s internal control over financial reporting;
- external financial audit process;
- compliance by the Company with legal and regulatory requirements; and
- independence and performance of the Company s internal and external auditors.

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

2. Roles and Responsibilities

I. Appointment of the Company s External Auditors

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

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

II. Oversight in Respect of Financial Disclosure

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

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

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

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

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

(e) review 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 in relation 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 Canadian Pension Plans (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 in relation 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.

Financial Highlights

Year ended December 31 (millions of dollars)	**2010**	2009	2008	2007	2006
Income					
Net income applicable to common shares					
Continuing operations	**1,227**	1,374	1,440	1,223	1,051
Discontinued operations					28
	1,227	1,374	1,440	1,223	1,079
Cash Flow					
Funds generated from operations	**3,331**	3,080	3,021	2,621	2,378
(Increase)/decrease in operating working capital	**(249)**	(90)	135	63	(506)
Net cash provided by operations	**3,082**	2,990	3,156	2,684	1,872
Capital expenditures and acquisitions	**5,036**	6,319	6,363	5,874	2,042
Balance Sheet					
Total assets	**46,589**	43,841	39,414	30,330	25,909
Long-term debt	**17,028**	16,186	15,368	12,377	10,887
Junior subordinated notes	**985**	1,036	1,213	975	
Preferred shares	**1,224**	539			
Common shareholders' equity	**15,503**	15,220	12,898	9,785	7,701

Common Share Statistics Year ended December 31	**2010**	2009	2008	2007	2006
Net income per share Basic					
Continuing operations	**$1.78**	$2.11	$2.53	$2.31	$2.15
Discontinued operations					0.06
	$1.78	$2.11	$2.53	$2.31	$2.21
Net income per share Diluted					
Continuing operations	**$1.77**	$2.11	$2.52	$2.30	$2.14
Discontinued operations					0.06
	$1.77	$2.11	$2.52	$2.30	$2.20
Dividends declared per share	**$1.60**	$1.52	$1.44	$1.36	$1.28

Common shares outstanding (millions)					
Average for the year	**690.5**	651.8	569.6	529.9	488.0
End of year	**696.2**	684.4	616.5	539.8	489.0

Chairman's Message

An inspiring leader can be difficult to replace, and this was one of the challenges we faced in 2010 with the retirement of Hal Kvisle. For more than a decade, Hal inspired others by demonstrating his and the company's values delivering results.

Orchestrating a smooth transition was a critical task for us, one that was a joint undertaking for both the Board and the CEO. Importantly, and to his credit, Hal communicated his impending departure and worked tirelessly grooming executives in the company.

We engaged external resources, and broadened the experience base of candidates allowing us a clear view of their capabilities. It was no accident that Russ Girling was positioned to succeed. His placement in high-level leadership positions over the last number of years ensured a smooth transition would occur when the time came for him to sit in the President and CEO's chair.

Succession is always important and the process in TransCanada is well crafted.

The Board and I wish Hal the best in his retirement and look forward to Russ continuing to grow long-term value for our shareholders, with the support of an experienced and capable executive leadership team.

This is an exciting time to guide TransCanada. Execution of the company's ambitious $20 billion capital program, managing the issues surrounding the low gas price environment and the political challenges of cross border pipelines are not insignificant. Fortunately, the strategies for success have been set by Hal and other leaders strategies Russ was instrumental in developing over the last decade.
Successful execution of those strategies for any company involves creating the right work environment. TransCanada received important recognition on this front in 2010. The company was included in Canada's top 100 employers, Alberta's top 50 employers for 2011, best employer for new Canadians and best diversity employer. TransCanada also maintained its ranking on the Dow Jones Sustainability Index for the ninth consecutive year one of only two Canadian energy companies to attain this recognition.

Beyond the internal support, the Board must also ensure the needs for retention and fair compensation for TransCanada's leadership team are balanced with actual performance and creation of shareholder value. Accommodating equity support for projects that deliver results beyond the term of compensation programs while diluting short term metrics requires some finesse. These are not formula driven tasks and I believe the Board has exercised prudent judgment in that balance.

To support that view, this year, the company has made a concerted effort to ensure shareholders understand the thorough processes at work in TransCanada. Often, actual practice surpasses the disclosure in the annual documents. To further exhibit transparency, much of the disclosure has been enhanced to more effectively close this gap.

There are many definitions of success but any form of success is dependent on dedication and effort. TransCanada continues to benefit from the daily, ongoing efforts of its 4,200 employees. It is the sum of these efforts that equals true success and for that I and my fellow Board members offer our thanks. Similarly, we offer our sincere thanks to Kerry Hawkins for his ongoing contributions as he is retiring from the Board after 15 years of dedicated service to shareholders and management.

On behalf of the Board of Directors;

S. Barry Jackson

2 CHAIRMAN'S MESSAGE

Letter to Shareholders

Strategies to Ensure Lasting, Long Term Value

A company's vision sets its direction for business planning, drives the right strategy and unites employees in achieving a common goal. But to achieve the vision, it must be executed with passion, hard work, discipline and exceptional decision-making at every level of the organization.

TransCanada's vision is unchanged over the last decade our goal is to become North America's leading energy infrastructure company. The company has clear priorities to ensure this goal is met priorities I have shared with the Board of Directors, the financial community and the many other stakeholders of our company. I would like to share with you the significant progress we made during 2010 and some of the opportunities for the years ahead.

Priority #1: TransCanada will focus on maximizing the value of its existing assets and ensure they continue to operate safely and reliably, delivering solid results.

Our base businesses generate approximately $4 billion of earnings before interest, taxes, depreciation and amortization (EBITDA)[1] each year. Our top priority is to protect the long term value of these assets and position them for future growth to ensure they continue to deliver stable and growing cash flow for decades to come.

In our pipeline businesses we continue to connect new supply to growing markets across North America. By maximizing the volume of natural gas and oil flowing through our pipelines we lower our unit costs and enhance our competitiveness and profitability.
This year we continued to successfully position our U.S. pipeline network to move U.S. shale gas, contracted approximately 200 MMcf/d of Marcellus gas to our Eastern Canada/U.S. delivery system, contracted approximately 2 Bcf/d of Northeast B.C. shale gas to our Alberta System and added significant U.S. crude oil volumes from the Bakken and Cushing areas to our Keystone pipeline.

We continue to develop new, cost competitive services to attract additional supply and meet our customers' changing needs. Importantly, today we are working with our customers on toll structure changes which will lower tolls, better reflect system usage and flow patterns and improve the competitiveness of the Canadian Mainline and the Western Canadian Sedimentary Basin. The Mainline is critical to moving North American gas supply to market.

In our power business we continue to maximize the long term profitability of our power plants through life extensions, higher plant availability, and increasing the output and the revenue we receive for the electricity we produce. During the year, we were able to implement plans that will significantly extend the operating life of Bruce A Units 3 and 4 and we increased the available capacity of Unit 30 at Ravenswood.

While our low-cost, base-load operations in Alberta and the U.S. Northeast have been impacted over the last few years by lower power prices, they remain very profitable and are well positioned to benefit as the economy recovers and commodity prices improve. In addition, the percentage of fixed price power sold under contract will increase over time as new power projects in our portfolio are completed and placed into service.

Ensuring we receive the maximum value from our assets over the long term requires the optimal balance of continuous cost improvement and reinvestment in maintenance capital to ensure the life of our assets is maximized. Properly done, our assets will be able to provide low cost, reliable service for decades to come. In 2010, we invested approximately $200 million in maintenance capital, at the same time capturing operating cost improvements across our assets from increased automation, improved processes and innovation. I am confident we have the right balance.

Doing all of this safely and without injury is an imperative. Our philosophy is every employee and contractor goes home safe every day. In 2010, our injury frequency rates were among the lowest in our industry. While we are very proud of this accomplishment, we believe a zero injury rate is possible and we will continue to strive to achieve that objective.

Priority #2: Complete the company's $20 billion capital program on time and on budget and ensure the cash flow associated with these assets comes on stream.

TransCanada is in the midst of an unprecedented $20 billion capital program that will see a number of attractive, low-risk pipeline and power projects placed into service over the next three years.

Today we are about halfway through this program, with approximately $10 billion of assets having recently started or about to commence commercial operations.

Our company's largest and most ambitious project the Keystone pipeline took a major step forward as it began flowing oil for the first time to refineries in Illinois in the summer of 2010.

Keystone marked a further milestone in February 2011 as the Cushing extension began transporting oil to market. At the same time Keystone's nominal capacity expanded to 591,000 Bbl/d.

The next step for the US$13 billion project is the U.S. Gulf Coast Expansion or Keystone XL. This portion of the pipeline system is expected to be operational in 2013. When completed, Keystone's overall commercial capacity will rise to 1.1 million Bbl/d with close to 1.0 million Bbl/d of that capacity contracted for an average term of 17 years. As volumes of Canadian and U.S. supplies grow, Keystone can very economically expand by another 400,000 Bbl/d, resulting in a total capacity of 1.5 million Bbl/d. This enormous project has significant energy security, employment and economic benefits to Canada and the United States and I remain confident we will obtain all major approvals this year.

Early in 2011, the US$630 million Bison pipeline began shipping natural gas from the U.S. Rockies to market. Just a few weeks prior to this, the $155 million Groundbirch pipeline went into service, delivering natural gas from Northeast B.C. through the Alberta System and on to North American markets. And in the spring of 2010, the $800 million North Central Corridor natural gas pipeline was finished on time and under budget.

In the fall of 2010, two major Energy projects were completed the second phase of the US$350 million Kibby Wind project in Maine and the $700 million Halton Hills Generating Station in Ontario.

Other major projects that are expected to become operational in 2011 include the US$360 million Guadalajara pipeline in Mexico and Arizona's US$500 million Coolidge Generating Station. Both are expected to begin operating in the second quarter. Construction of the remaining stages of the Cartier Wind Energy project in Québec is progressing and they are expected to be operational in late 2011 and 2012.

The Bruce Power refurbishment involving Units 2 and 1 is scheduled to be complete in the first and third quarters of 2012 respectively.

While it has taken significantly longer and cost more to complete the re-start than originally anticipated, we are confident in our current estimates and schedule. In recent months, significant progress has been made and we are now in the home stretch of completing the project. Despite the challenges, once Units 1 and 2 are returned to service they will generate 1,500 MW of much needed, emissions free power for the residents of Ontario and deliver attractive, long-term returns for our shareholders.

Priority #3: Maintain our financial strength and flexibility to ensure we can continue to fund the existing capital program and invest in our growth prospects as we move forward.

In 2010, TransCanada continued to deliver strong financial and operating results. Comparable earnings(1) were $1.4 billion or $1.97 per share. Net income applicable to common shares totalled $1.2 billion or $1.78 per share. Funds generated from operations(1) increased to a record $3.3 billion on the strength of our diverse portfolio of North American energy infrastructure assets.

For the eleventh consecutive year, in February 2011 TransCanada's Board of Directors increased the dividend on common shares. The new quarterly dividend of $0.42 per common share equates to $1.68 per share on an annualized basis an increase of five per cent over 2010.

Over the past decade, we have continuously strengthened our balance sheet to ensure we have the capacity to fund our capital program and on-going growth in all economic environments. This strategy served the company well during the turbulence of the economic downturn experienced over the past few years and allowed us to maintain 'A' grade credit ratings.

Since the onset of the financial crisis in the second half of 2008, TransCanada has raised approximately $11.5 billion in the capital markets, including $3 billion of common equity, to fund our $20 billion capital program.

Our success in issuing US$2.25 billion of long-term debt and $700 million of preferred shares in 2010 at very attractive rates is a testament to the company's continued financial strength.

While we recognize issuing both debt and equity to fund a long cycle capital program has had an impact on our reported earnings per share over the last two years, these investments will deliver long term growth in cash flow, earnings and dividends.

As we complete our current capital program between now and 2013, we expect to generate an additional $2 billion of EBITDA[(1)] annually, bringing our forecast total to approximately $6 billion per year.

This, in turn, is expected to lead to a robust increase in discretionary cash flow. By 2013 we expect to generate approximately $4 billion of funds from operations[(1)] per year. This will provide us with significant financial capacity to invest in our core businesses; continue to increase dividends to shareholders; and to further enhance our financial strength and flexibility. Our decisions will be guided by our desire to maximize long-term shareholder value while 'living within our means'.

Priority #4: Reinvest TransCanada's growing cash flow in high quality, low risk projects.

Going forward, TransCanada has three large platforms for growth Natural Gas Pipelines, Oil Pipelines and Energy. All three have strong long-term fundamentals.

Over the next decade, the demand for natural gas in North America is expected to grow by approximately 10 Bcf/d, powered by the expected growth in demand for electricity. Today, our pipeline network taps into virtually every major North American natural gas supply basin on the continent and provides our customers with unparalleled access to premium markets. Looking forward, we are very well positioned to connect shale gas, conventional gas, LNG in Mexico and, in the longer term, northern gas to growing markets.

We have captured the pre-eminent position to move growing supplies of crude oil from Western Canada and the Williston Basin in the United States to the largest refining centres in North America.

Western Canadian crude oil supply is expected to grow by approximately 1.1 million Bbl/d over the next decade. At the same time, industry experts project that production from the Williston Basin could grow by as much as 200,000 Bbl/d between now and 2015.

TransCanada is well positioned to move growing oil production from both these areas to large refining centres in the U.S. Midwest and Gulf Coast regions through the Keystone Oil Pipeline and our related Bakken and Cushing Marketlink projects.

In Energy, power demand is expected to grow at an average annual rate of approximately one per cent over the next ten years. While coal, nuclear and hydro will remain key components of the supply mix, it is likely that gas-fired generation, renewables and nuclear refurbishments will play a major role in meeting future demand as the North American market transitions to a less carbon intensive mix. Our proven track record in the development of natural gas, hydro, wind and nuclear will allow us to continue to capture high quality long term opportunities in our core markets.

We have enjoyed tremendous success over the past decade under the leadership of Hal Kvisle. We have focused on businesses in which we have considerable expertise and in geographies where we have distinct competitive advantage. The 4,200 employees of this company are the best in their fields and they deliver superior results every day. Together, they accomplish big things and they do it safely and with great care. I thank them all for their accomplishments. I am very proud and honoured to have the opportunity to work with them.

Going forward, I believe we have the right people, the right skills, the right assets, the right strategy and the financial capacity to compete and win a significant share of the quality opportunities available in our core markets and ultimately realize our vision to be North America's leading energy infrastructure company. I am very excited about our future. As the TransCanada leadership team, along with its 4,200 employees, moves these priorities forward, we will increase cash flow, increase earnings and grow our dividend resulting in continued long term, sustainable growth for our shareholders.

Russell K. Girling
President and Chief Executive Officer

(1) Non-GAAP measure that does not have any standardized meaning prescribed by generally accepted accounting principles. For more information see Non-GAAP Measures in the Management's Discussion and Analysis of the 2010 Annual Report.

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Management's Discussion and Analysis (MD&A) dated February 14, 2011 should be read in conjunction with the accompanying audited Consolidated Financial Statements of TransCanada Corporation (TransCanada or the Company) and the notes thereto for the year ended December 31, 2010 which are prepared in accordance with Canadian generally accepted accounting principles (GAAP). This MD&A covers TransCanada's financial position and operations as at and for the year ended December 31, 2010. "TransCanada" or "the Company" includes TransCanada Corporation 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 2010 Annual Report.

TRANSCANADA OVERVIEW

With more than 50 years experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure, including natural gas and oil pipelines, power generation and natural gas storage facilities.

In pursuing its vision to be the leading energy infrastructure company in North America, TransCanada strives to execute on its portfolio of large, attractive growth projects. Each of these new projects is supported by strong business fundamentals and long-term contracts.

With assets of approximately $47 billion and a substantial growth portfolio, TransCanada believes it is well positioned to build on its track record of strong and sustainable earnings and cash flow.

At December 31, 2010, TransCanada had completed construction and placed in service, or will place in service in early 2011, approximately $10 billion of its $20 billion capital growth program. In 2010, TransCanada spent $2.3 billion to advance or complete construction of several major Natural Gas Pipeline and Energy projects, including placing five projects in service. In addition, the Company completed the first two phases of the Keystone crude oil pipeline with capital expenditures of $2.7 billion.

TransCanada's 2010 Key Accomplishments

The Company advanced a significant portion of the Keystone oil pipeline extending from Hardisty, Alberta to markets in the United States (U.S.) Midwest, including the following:

- commenced operating at a low operating pressure as the first phase of Keystone began delivering oil to Wood River and Patoka in Illinois (Wood River/Patoka) in June 2010; and
- completed construction of the extension to Cushing, Oklahoma (Cushing Extension) and commenced line fill in late 2010. The Cushing Extension was in service at the beginning of February 2011.

The Company completed construction, placed in service and advanced the following initiatives in natural gas pipelines, which included connecting new shale and unconventional natural gas supply:

- completed the final portion of the $800 million North Central Corridor (NCC) pipeline in northern Alberta in early 2010, providing capacity to shippers on the Alberta System to address increasing natural gas supply in northwestern Alberta and northeastern British Columbia (B.C.). The project was completed on schedule and under budget;
- completed the US$630 million Bison pipeline in late December 2010, delivering natural gas from the Powder River Basin in Wyoming. The pipeline was placed in service in January 2011;
- completed the $155 million Groundbirch pipeline in December 2010, on schedule and under budget, and began transporting natural gas from the Montney shale gas formation into the Alberta System;
- received approval from the National Energy Board (NEB) in January 2011 to construct the approximate $310 million Horn River natural gas pipeline, which is expected to transport natural gas from the Horn River shale gas formation starting in second quarter 2012; and
- advanced construction of the Guadalajara pipeline, which will move natural gas from Manzanillo to Guadalajara in Mexico and was 70 per cent complete as of December 31, 2010. The US$360 million project is expected to be operational in second quarter 2011.

The Company completed, placed in service and advanced the following power generation assets:

- completed the $700 million, 683 megawatt (MW) Halton Hills generating station, on time and on budget, in the fall of 2010 when it began delivering low-emission, natural gas-sourced power to the Ontario market;

- completed the US$350 million Kibby Wind project, a 44 turbine, 132 MW wind farm in Maine ahead of schedule and on budget; and

- advanced construction of the US$500 million Coolidge generation station, which is approximately 95 per cent complete, with commissioning approximately 80 per cent finished. Coolidge is anticipated to be in service in second quarter 2011.

TransCanada's Businesses Are Organized Into Three Segments Natural Gas Pipelines, Oil Pipelines and Energy

The Natural Gas Pipelines and Oil Pipelines businesses consist of large-scale natural gas and crude oil pipelines, respectively, primarily situated in Canada and the U.S. TransCanada is also the general partner of TC PipeLines, LP (PipeLines LP), a limited partnership that owns interests in U.S. natural gas pipelines.

Natural Gas Pipelines

TransCanada's natural gas pipeline systems consist of a network of more than 60,000 kilometres (km) (37,000 miles) of wholly owned and operated natural gas pipelines, and more than 8,800 km (5,500 miles) of partially owned natural gas pipelines. The network connects major natural gas supply basins and markets, transporting approximately 20 per cent of the natural gas consumed in North America or 14 billion cubic feet (Bcf) of natural gas per day, which is delivered to local distribution companies, power generation facilities and other businesses in markets across North America. The Company's U.S. Natural Gas Pipelines also include regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf.

TransCanada is also pursuing additional natural gas pipelines projects to diversify the supply side of the business and add incremental value to existing assets. Key areas of focus include greenfield development opportunities to connect TransCanada's natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies, and over the longer term, to northern natural gas reserves. TransCanada is also pursuing opportunities to optimize its existing natural gas pipelines systems to respond to the changing flow patterns of natural gas supply in North America.

Oil Pipelines

With increasing production of crude oil in Alberta and new crude oil discoveries in the U.S., including the Bakken shale play in Montana and North Dakota, along with growing demand for secure, reliable sources of energy, TransCanada has identified opportunities to develop new oil pipeline capacity. The Keystone oil pipeline complements the Company's natural gas transmission business and draws on its pipelines experience. This large-scale crude oil pipeline system, designed to initially carry 1.1 million barrels per day (Bbl/d), comprises the completed 3,467 km (2,154 miles) Wood River/Patoka and Cushing Extension phases, and a proposed 2,673 km (1,661 miles) U.S. Gulf Coast Expansion project (collectively, Keystone). Future expansions could increase the capacity of Keystone to 1.5 million Bbl/d.

Energy

TransCanada's Energy business primarily consists of a portfolio of essential power generation assets in select regions of Canada and the U.S., and unregulated natural gas storage assets in Alberta.

TransCanada owns, controls or is developing more than 10,800 MW of power generation, comprising a diverse portfolio that includes power sourced from natural gas, nuclear, coal, hydro and wind assets. TransCanada's power business is primarily located in Alberta, Ontario and Québec and in the northeastern U.S., mainly in the New England states, and New York. The assets are largely underpinned by long-term tolling contracts or represent low-cost baseload generation and essential capacity.

From offices in Western Canada, Ontario and the northeastern U.S., TransCanada complements these assets by conducting wholesale and retail electricity marketing and trading throughout North America.

In addition to power generation assets in the Energy business, TransCanada owns or controls approximately 130 Bcf of unregulated natural gas storage capacity in Alberta, or approximately one-third of all storage capacity in the province. Combined with the regulated natural gas storage in Michigan included in Natural Gas Pipelines, TransCanada provides natural gas storage and related services for approximately 380 Bcf of capacity.

TRANSCANADA'S STRATEGY

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

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

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

TransCanada relies on a low-risk business model to maximize the full-life value of its existing assets and commercial positions. In the Natural Gas Pipelines and Oil Pipelines businesses, 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 the Energy business, highly efficient, large-scale power generation facilities supply markets through long-term power purchase and sale agreements and low-volatility, shorter-term commercial arrangements. TransCanada's growing investments in natural gas, nuclear, wind and hydro-power 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 TransCanada's business model.

Commercially develop and physically execute new asset investment programs

TransCanada's expertise, scale and financial capacity enable access to attractive commercial, financing and input cost arrangements that underpin the quality of growth projects, notably the current $20 billion capital program that began generating revenue in 2010. The remainder of these projects will provide further contributions to the Company's earnings over the next three years as they are put in service. Success in this capital program requires effective performance in engineering and in project and operational set-up and delivery. It also requires regulatory, legal and financing support. TransCanada's model for managing construction risks and maximizing capital productivity helps ensure disciplined attention to quality, cost and schedule that produces service for its customers and returns to its shareholders. Many of these functional capabilities also form the basis for successful acquisition and integration of new energy and pipeline facilities, an important dimension of the Company's growth strategy.

Cultivate a focused portfolio of high-quality development options

The Company's core regions within North America are the focus of pipelines and energy growth initiatives. TransCanada will continue to pursue opportunities to connect long-life shale and conventional natural gas resources in Western Canada, Northern Canada, Alaska, the U.S. Rockies, the U.S. midcontinent and the U.S. Gulf Coast supply regions. TransCanada will also continue to pursue opportunities to connect growing crude oil volumes from the Alberta oil sands and U.S. sources, including the Bakken formation of the Williston basin, to preferred North American markets. In addition, the Company will continue to assess energy infrastructure acquisition opportunities that complement its existing assets and provide access to new supply and market regions. In the Energy business, the Company will continue to focus on low-cost, long-life baseload power generating and natural gas storage assets supported by firm, long-term contracts with creditworthy counterparties. Selected opportunities will advance to full development and construction when market conditions are appropriate and project risks are manageable.

Maximize TransCanada's competitive strengths

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

CONSOLIDATED FINANCIAL REVIEW

SELECTED THREE-YEAR CONSOLIDATED FINANCIAL DATA

(millions of dollars except per share amounts)	**2010**	2009	2008
Income Statement			
Revenues	**8,064**	8,181	8,547
Comparable EBITDA[1]	**3,941**	4,107	4,125
Net Income	**1,272**	1,380	1,440
Preferred Share Dividends	**45**	6	
Net Income Applicable to Common Shares	**1,227**	1,374	1,440
Comparable Earnings[1]	**1,361**	1,325	1,279
Per Share Data			
Net Income per Common Share			
Basic	**$1.78**	$2.11	$2.53
Diluted	**$1.77**	$2.11	$2.52
Comparable Earnings per Common Share[1]	**$1.97**	$2.03	$2.25
Dividends Declared			
Per Common Share	**$1.60**	$1.52	$1.44
Per Class 1 Preferred Share[2]	**$1.15**	$0.2899	
Per Class 3 Preferred Share[2]	**$0.8041**		
Per Class 5 Preferred Share[2]	**$0.6457**		
Cash Flows			
Funds generated from operations[1]	**3,331**	3,080	3,021
(Increase)/decrease in operating working capital	**(249)**	(90)	135
Net Cash Provided by Operations	**3,082**	2,990	3,156
Capital Expenditures	**5,036**	5,417	3,134
Acquisitions, Net of Cash Acquired		902	3,229
Balance Sheet			
Total Assets	**46,589**	43,841	39,414
Total Long-Term Liabilities	**23,044**	21,959	20,158

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable Earnings, Comparable Earnings per Share and Funds Generated from Operations.

(2) The Company issued Class 1, 3 and 5 preferred shares in September 2009, March 2010 and June 2010, respectively.

HIGHLIGHTS

Earnings

Net Income was $1,272 million and Net Income Applicable to Common Shares was $1,227 million or $1.78 per share in 2010 compared to $1,380 million and $1,374 million or $2.11 per share, respectively, in 2009.

TransCanada's Comparable Earnings of $1,361 million or $1.97 per share in 2010 excluded a $127 million after-tax valuation provision for the Mackenzie Gas Project (MGP).

Cash Flow

Funds Generated from Operations were $3.3 billion in 2010, an increase of $0.2 billion from 2009.

TransCanada invested $5.0 billion in its Natural Gas Pipelines, Oil Pipelines and Energy capital projects in 2010, including the following:

- capital expenditures of $1.2 billion for Natural Gas Pipelines projects, including expansion of the Alberta System and construction of Bison and Guadalajara;
- capital expenditures of $2.7 billion for Keystone; and
- capital expenditures of $1.1 billion for Energy projects, including the refurbishment and restart of Bruce A Units 1 and 2, and construction of Coolidge, Halton Hills and Cartier Wind.

In 2010, TransCanada issued approximately $2.4 billion of long-term debt, $0.7 billion of preferred shares and $0.4 billion of common shares, primarily comprising the following:

- in September 2010, the issuance of US$1.0 billion of senior notes;
- in June 2010, the issuance of 14 million Series 5 preferred shares at $25 per share, resulting in gross proceeds of $350 million;
- in June 2010, the issuance of US$1.25 billion of senior notes;
- in March 2010, the issuance of 14 million Series 3 preferred shares at $25 per share, resulting in gross proceeds of $350 million; and
- in accordance with its Dividend Reinvestment and Share Purchase Plan (DRP), the issuance of approximately 11 million common shares from treasury in lieu of making cash dividend payments totalling $378 million.

Balance Sheet

Total assets increased by $2.8 billion to $46.6 billion in 2010 from 2009, primarily due to investments in capital projects, described above.

TransCanada's Shareholders' Equity increased by $1.0 billion to $16.7 billion in 2010 from 2009.

Dividends

On February 14, 2011, the Board of Directors of TransCanada increased the quarterly dividend on the Company's outstanding common shares by five per cent to $0.42 per share from $0.40 per share for the quarter ending March 31, 2011. This was the eleventh consecutive year in which the common share dividend was increased. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011, and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2011.

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

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

Year ended December 31, 2010 *(millions of dollars except per share amounts)*	**Natural Gas Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA[1]	**2,915**	**1,125**	**(99)**	**3,941**
Depreciation and amortization	**(977)**	**(377)**		**(1,354)**
Comparable EBIT[1]	**1,938**	**748**	**(99)**	**2,587**
Specific items:				
Valuation provision for MGP	**(146)**			**(146)**
Risk management activities		**(8)**		**(8)**
EBIT[1]	**1,792**	**740**	**(99)**	**2,433**
Interest expense				**(701)**
Interest expense of joint ventures				**(59)**
Interest income and other				**94**
Income taxes				**(380)**
Non-controlling interests				**(115)**
Net Income				**1,272**
Preferred share dividends				**(45)**
Net Income Applicable to Common Shares				**1,227**
Specific items (net of tax):				
Valuation provision for MGP				**127**
Risk management activities				**7**
Comparable Earnings[1]				**1,361**
Net Income per Share Basic				**$1.78**
Comparable Earnings per Share[1][2]				**$1.97**

Year ended December 31, 2009 *(millions of dollars except per share amounts)*				
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
Risk management activities		1		1
EBIT[1]	2,092	785	(117)	2,760
Interest expense				(954)
Interest expense of joint ventures				(64)
Interest income and other				121
Income taxes				(387)
Non-controlling interests				(96)

Net Income	1,380
Preferred share dividends	(6)
Net Income Applicable to Common Shares	1,374
Specific items (net of tax where applicable):	
Dilution gain from reduced interest in PipeLines LP	(18)
Risk management activities	(1)
Income tax adjustments	(30)
Comparable Earnings(1)	1,325
Net Income per Share Basic	$2.11
Comparable Earnings per Share(1)(2)	$2.03

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

Year ended December 31, 2008 *(millions of dollars except per share amounts)*	Natural Gas 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 distributions	279			279
GTN lawsuit settlement	17			17
Write-down of Broadwater LNG project costs		(41)		(41)
EBIT[1]	2,326	911	(104)	3,133
Interest expense				(943)
Interest expense of joint ventures				(72)
Interest income and other				54
Income taxes				(602)
Non-controlling interests				(130)
Net Income				1,440
Specific items (net of tax where applicable):				
Calpine bankruptcy distributions				(152)
GTN lawsuit settlement				(10)
Write-down of Broadwater LNG project costs				27
Income tax adjustments				(26)
Comparable Earnings[1]				1,279
Net Income per Share Basic				$2.53
Comparable Earnings per Share[1][2]				$2.25

[1]Refer to the Non-GAAP Measures section in this MD&A for further discussion of Comparable EBITDA, Comparable EBIT, EBIT, Comparable Earnings and Comparable Earnings per Share.

	2010	2009	2008
[2]**Comparable Earnings per Share**[1]	**$1.97**	$2.03	$2.25
Specific items per share (net of tax where applicable):			
Valuation provision for MGP	**(0.18)**		
Risk management activities	**(0.01)**		
Dilution gain from reduced interest in PipeLines LP		0.03	
Calpine bankruptcy distributions			0.27
GTN lawsuit settlement			0.02
Write-down of Broadwater LNG project costs			(0.05)
Income tax adjustments		0.05	0.04
Net Income per Share	**$1.78**	$2.11	$2.53

RESULTS OF OPERATIONS

TransCanada had Net Income of $1,272 million and Net Income Applicable to Common Shares of $1,227 million or $1.78 per share in 2010 compared to $1,380 million and $1,374 million or $2.11 per share, respectively, in 2009. Net Income in 2008 was $1,440 million or $2.53 per share.

Comparable Earnings in 2010, 2009 and 2008 were $1,361 million or $1.97 per share, $1,325 million or $2.03 per share and $1,279 million or $2.25 per share, respectively. Comparable Earnings in 2010 excluded a $127 million after-tax ($146 million pre-tax) valuation provision for advances to the Aboriginal Pipeline Group (APG) for the MGP. Comparable Earnings in 2010 also excluded $7 million of net unrealized after-tax losses ($8 million pre-tax) (2009 after-tax and pre-tax gains of $1 million; 2008 nil) resulting from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities.

Comparable Earnings in 2009 also excluded $30 million of favourable income tax adjustments arising from a reduction in the Province of Ontario's corporate income tax rates and an $18 million after-tax ($29 million pre-tax) dilution gain resulting from TransCanada's reduced interest in PipeLines LP after a public offering of PipeLines LP common units in fourth quarter 2009. Comparable Earnings in 2008 excluded $152 million of after-tax gains ($279 million pre-tax) on the disposition of shares received by GTN and Portland from Calpine Corporation (Calpine) bankruptcy distributions, $10 million after tax ($17 million pre-tax) of GTN lawsuit settlement proceeds and a $27 million after-tax ($41 million pre-tax) write-down of costs previously capitalized for the Broadwater liquefied natural gas (LNG) project. Comparable Earnings in 2008 also excluded $26 million of favourable income tax adjustments from an internal restructuring and realization of losses.

Comparable Earnings increased $36 million and decreased $0.06 per share in 2010 from 2009. The increase in Comparable Earnings reflected:

- decreased Comparable Earnings Before Interest and Taxes (EBIT) from Natural Gas Pipelines primarily due to the negative impact in 2010 of a weaker U.S. dollar on Natural Gas Pipelines' U.S. operations, a decrease in Canadian Mainline revenues due to decreased amounts recovered on a flow-through basis, and reduced revenues for Great Lakes. These decreases were partially offset by decreased operating, maintenance and administration (OM&A) costs, reduced depreciation expense primarily for Great Lakes, increased revenue for Northern Border and higher earnings as a result of an Alberta System revenue requirement settlement;

- decreased Comparable EBIT from Energy primarily due to lower realized power prices for Western Power and Bruce B, and lower Natural Gas Storage price spreads, partially offset by higher capacity revenues at Ravenswood and incremental earnings from the start up of Halton Hills, Portlands Energy and Kibby Wind;

- decreased Comparable EBIT loss from Corporate primarily due to lower support services and other corporate costs;

- decreased Interest Expense primarily due to an increase in capitalized interest relating to Keystone and other capital projects, the positive impact of a weaker U.S. dollar on U.S. dollar-denominated interest expense, and Canadian debt maturities, partially offset by interest expense for long-term debt issuances in 2010 and increased losses from changes in the fair value of derivatives used to manage the Company's exposure to fluctuating interest rates;

- decreased Interest Income and Other due to a higher positive impact in 2009 compared to 2010 of a weakening U.S. dollar on U.S. dollar working capital balances throughout the year;

- decreased Income Taxes due to reduced pre-tax earnings in 2010, partially offset by positive tax adjustments in 2009;

- an increase in Non-Controlling Interests due to higher PipeLines LP earnings; and

- increased preferred share dividends recorded on preferred shares issued in 2010 and third quarter 2009.

Comparable Earnings increased $46 million and decreased $0.22 per share in 2009 compared to 2008. Comparable Earnings reflected an increase in Comparable EBIT primarily as a result of higher realized power prices for Bruce Power,

the positive impact in 2009 of a stronger U.S. dollar on Natural Gas Pipelines' U.S. operations, incremental earnings from the start-up of Portlands Energy and the Carleton phase of Cartier Wind, and higher earnings from the Alberta System revenue requirement settlement, partially offset by lower realized power prices in Western Power and U.S. Power, and increased costs for developing the Alaska Pipeline Project.

Net Income per Share and Comparable Earnings per Share in 2010 and 2009 were reduced by the increase in the average number of common shares outstanding following the Company's issuance of 58.4 million common shares in second quarter 2009 as well as common shares issued under the DRP. Net Income per Share and Comparable Earnings per Share in 2009 were also reduced by the issuance of 35.1 million and 34.7 million common shares in fourth quarter 2008 and second quarter 2008, respectively. The shares were issued to partially finance TransCanada's extensive capital growth program and acquisitions.

On a consolidated basis, the impact of changes in the value of the U.S. dollar on U.S. Natural Gas Pipelines and U.S. Energy EBIT is partially offset by U.S. dollar-denominated interest expense. The resultant net exposure is managed using derivatives, further reducing the Company's exposure to changes in U.S. foreign exchange rates.

Further discussion of these items is included in the Natural Gas Pipelines, Energy, Corporate and Other Income Statement Items sections in 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 TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada'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 TransCanada and its subsidiaries, expectations or projections about the future, strategies and goals for growth and expansion, expected and future cash flows, costs, schedules (including anticipated construction and completion dates), operating and financial results, and expected impact of future commitments and contingent liabilities. All forward-looking statements reflect TransCanada'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 TransCanada 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 Natural Gas Pipelines, Oil Pipelines, Energy and Risk Management and Financial Instruments sections in this MD&A, which could cause TransCanada'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 TransCanada 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. TransCanada 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

TransCanada uses the measures Comparable Earnings, Comparable Earnings per Share, Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA), 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 TransCanada 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 TransCanada'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 and is generally used to better measure performance and evaluate trends of individual assets. EBITDA comprises earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, non-controlling interests and preferred share dividends. EBIT is a measure of the Company's earnings from ongoing operations and is generally used to better measure performance and evaluate trends within each segment. EBIT comprises earnings before deducting interest and other financial charges, income taxes, non-controlling interests and preferred share dividends.

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, write-downs of assets and investments, and certain fair value adjustments on risk management activities. The Reconciliation of Comparable EBITDA, Comparable EBIT, EBIT and Comparable Earnings to Net Income Applicable to Common Shares 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. Comparable Earnings per Share is calculated by dividing Comparable Earnings by the weighted average number of common shares outstanding for the year.

Funds Generated from Operations comprise Net Cash Provided by Operations before changes in operating working capital and allows management to better measure consolidated operating cash flow, excluding fluctuations from working capital balances which may not necessarily be reflective of underlying operations in the same period. 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 in this MD&A.

OUTLOOK

TransCanada's corporate strategy is to maximize the full-life value of its existing assets and commercial positions, and to pursue long-term growth opportunities that add long-term shareholder value while focusing on core strengths in its pipelines and energy businesses in North America. In 2011 and beyond, TransCanada expects its net income and operating cash flow combined with a strong balance sheet and its proven ability to access capital markets will provide the financial resources needed to complete its $20 billion capital expenditure program, to continue pursuing additional long-term growth opportunities and to create additional value for its shareholders. This strategy will be executed with the same discipline and deliberate manner that characterized TransCanada's capital expenditure program in previous years. In 2011, the Company will continue to advance its capital program and implement its strategy to grow the Natural Gas Pipelines, Oil Pipelines and Energy businesses as discussed in the TransCanada's Strategy section in this MD&A.

In February 2011, TransCanada began recording EBITDA for Keystone's Wood River/Patoka and Cushing Extension phases. Keystone's EBITDA could be impacted by levels of spot volumes transported. Spot volumes transported are affected by customer demand, market pricing, refinery, terminal and pipeline facility outages, and the associated rates charged.

In addition, TransCanada expects a positive impact on its 2011 earnings from assets that were placed in service in 2010 and early 2011 such as NCC, Groundbirch, Bison, Halton Hills and Kibby Wind, and from assets that are expected to be placed in service later in 2011, such as Guadalajara and Coolidge. TransCanada expects that, as these new assets are placed in service in 2011, its consolidated earnings for the year will be affected by a reduction in capitalized interest and an increase in depreciation.

Natural Gas Pipelines' EBIT in 2011 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 EBIT in 2011 will be affected by the current economic climate which continues to dampen demand growth, market liquidity, as well as commodity and capacity prices. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by the current lower price environment. Energy's EBIT in 2011 will be positively affected by assets that were placed in service during 2010 and assets that are expected to be placed in service in 2011.

TransCanada's earnings from its U.S. Natural Gas Pipelines, Oil Pipelines and Energy businesses are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's Net Income. As new assets are placed in service in the U.S., this exposure is expected to increase as EBIT from U.S. operations increases. This impact is expected to be partially offset by changes in the value of U.S. dollar-denominated interest expense. In addition, the Company expects to continue to use derivatives to manage its resultant net exposure to changes in U.S. dollar exchange rates.

The Company's results in 2011 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 and Business Risks sections for Natural Gas Pipelines, Oil Pipelines and Energy. Refer to the Outlook sections in this MD&A for further discussion on the outlook for Natural Gas Pipelines, Oil Pipelines and Energy.

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

NATURAL GAS PIPELINES

CANADIAN MAINLINE The Canadian Mainline is a 14,101 km (8,762 miles) 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.

ALBERTA SYSTEM The Alberta System is a 24,187 km (15,029 miles) natural gas transmission system in Alberta and Northeast B.C. 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) natural gas transmission system that extends from producing fields located in the Texas and Oklahoma panhandle regions, from the offshore and onshore regions of the Gulf of Mexico, and from the U.S. midcontinent region to markets located mainly in Wisconsin, Michigan, Illinois, Indiana and Ohio. 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 2,178 km (1,353 miles) natural gas transmission system that transports WCSB and Rocky Mountain-sourced natural gas to third-party natural gas pipelines and markets in Washington, Oregon and California, and connects 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 comprises a 161 km (100 miles) pipeline supplying natural gas to the oil sands region near Fort McMurray, Alberta and a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.

BISON Bison is a 487 km (303 miles) natural gas pipeline that was placed in service in January 2011 and connects supply from the Powder River Basin in Wyoming to Northern Border in North Dakota.

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 138 km (86 miles) from Ehrenberg, Arizona to Ogilby, California and connecting with a third-party natural gas pipeline system in Mexico. TransCanada 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. TransCanada operates Tuscarora and effectively owns 38.2 per cent of the system through its 38.2 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. TransCanada operates Northern Border and effectively owns 19.1 per cent of the system through its 38.2 per cent interest in PipeLines LP.

GREAT LAKES Owned 53.6 per cent by TransCanada 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 Eastern Canada and the U.S. Northeast and Midwest regions. TransCanada operates Great Lakes and effectively owns 71.3 per cent of the system through the combination of its direct ownership interest and its 38.2 per cent interest in PipeLines LP.

IROQUOIS Owned 44.5 per cent by TransCanada, 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 TransCanada, TQM is a 572 km (355 miles) pipeline system that connects with the Canadian Mainline near the Québec/Ontario border, transports natural gas to markets in Québec, and connects with Portland. TQM is operated by TransCanada.

PORTLAND Owned 61.7 per cent by TransCanada, 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 TransCanada.

TRANSGAS Owned 46.5 per cent by TransCanada, 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 TransCanada, Gas Pacifico is a 540 km (336 miles) natural gas pipeline extending from Loma de la Lata, Argentina to Concepción, Chile. TransCanada 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.

GUADALAJARA The Guadalajara natural gas pipeline is under construction and when completed in 2011 will extend approximately 305 km (190 miles) from Manzanillo to Guadalajara in Mexico.

ALASKA PIPELINE PROJECT The Alaska Pipeline Project is a proposed natural gas pipeline and treatment plant. The pipeline would extend 2,737 km (1,700 miles) from the treatment plant at Prudhoe Bay, Alaska to Alberta. TransCanada has also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska. TransCanada has entered into an agreement with ExxonMobil to jointly advance the project.

MACKENZIE GAS PROJECT The Mackenzie Gas Project is a proposed natural gas pipeline extending 1,196 km (743 miles) that would connect northern onshore natural gas fields with North American markets. TransCanada has the right to acquire an equity interest in the project.

OIL PIPELINE

KEYSTONE Keystone is a 3,467 km (2,154 miles) crude oil pipeline extending from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and from Steele City, Nebraska to Cushing, Oklahoma. The Wood River/Patoka and Cushing Extension phases commenced commercial operations in June 2010 and February 2011, respectively. In addition, TransCanada plans to construct the U.S. Gulf Coast Expansion, a 2,673 km (1,661 miles) extension and expansion of the pipeline to the U.S. Gulf Coast.

NATURAL GAS PIPELINES

NATURAL GAS PIPELINES HIGHLIGHTS

Comparable EBIT from Natural Gas Pipelines was $1.9 billion in 2010, a decrease of $0.2 billion from $2.1 billion in 2009.

The Company invested $1.2 billion in Natural Gas Pipelines capital projects in 2010.

Construction was completed on the Bison natural gas pipeline in late 2010 and became operational in January 2011.

During 2010, the NEB approved the Company's Alberta System 2010 - 2012 Revenue Requirement Settlement application. The NEB also approved the Company's application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System.

In March 2010, the Company completed the final phase of the Alberta System's NCC expansion at a total capital cost of approximately $800 million. The Alberta System's Groundbirch pipeline was completed in December 2010 at a total capital cost of approximately $155 million.

In December 2010, the NEB issued its decision approving the MGP subject to the project proponents meeting certain conditions and deadlines. Nevertheless, uncertainty persists with respect to the project. Accordingly, at December 31, 2010, the Company recorded a valuation provision of $146 million. TransCanada remains committed to advancing the project.

In January 2011, the NEB approved the construction of the approximately $310 million Horn River pipeline, which is expected to commence operations in second quarter 2012.

NATURAL GAS PIPELINES RESULTS

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Canadian Natural Gas Pipelines			
Canadian Mainline	**1,054**	1,133	1,141
Alberta System	**742**	728	692
Foothills	**135**	132	133
Other (TQM, Ventures LP)	**50**	59	50
Canadian Natural Gas Pipelines Comparable EBITDA[(1)]	**1,981**	2,052	2,016
Depreciation and amortization	**(715)**	(714)	(702)
Canadian Natural Gas Pipelines Comparable EBIT[(1)]	**1,266**	1,338	1,314
U.S. Natural Gas Pipelines (in U.S. dollars)			
ANR	**314**	300	327
GTN[(2)]	**171**	170	185
Great Lakes[(3)]	**109**	120	118
PipeLines LP[(2)(4)]	**99**	90	84
Iroquois	**67**	68	55
Portland[(5)]	**22**	22	25
International (Tamazunchale, TransGas, Gas Pacifico/INNERGY)	**42**	52	38
General, administrative and support costs[(6)]	**(31)**	(17)	(17)
Non-controlling interests[(7)]	**173**	153	161
U.S. Natural Gas Pipelines Comparable EBITDA[(1)]	**966**	958	976
Depreciation and amortization	**(256)**	(276)	(272)
U.S. Natural Gas Pipelines Comparable EBIT[(1)]	**710**	682	704
Foreign exchange	**24**	105	49
U.S. Natural Gas Pipelines Comparable EBIT[(1)] (in Canadian dollars)	**734**	787	753
Natural Gas Pipelines Business Development Comparable EBITDA and EBIT[(1)]	**(62)**	(62)	(37)
Natural Gas Pipelines Comparable EBIT[(1)]	**1,938**	2,063	2,030
Summary:			
Natural Gas Pipelines Comparable EBITDA[(1)]	**2,915**	3,093	3,019
Depreciation and amortization	**(977)**	(1,030)	(989)
Natural Gas Pipelines Comparable EBIT[(1)]	**1,938**	2,063	2,030
Specific items:			
Valuation provision for MGP[(8)]	**(146)**		
Dilution gain from reduced interest in PipeLines LP[(3)(9)]		29	
Calpine bankruptcy distributions[(10)]			279
GTN lawsuit settlement			17
Natural Gas Pipelines EBIT[(1)]	**1,792**	2,092	2,326

(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 North Baja was sold to PipeLines LP.

(3) Represents the Company's 53.6 per cent direct ownership interest.

(4) Effective November 18, 2009, PipeLines LP's results reflected TransCanada's effective ownership in PipeLines LP of 38.2 per cent. From July 1, 2009 to November 17, 2009, TransCanada's ownership interest in PipeLines LP was 42.6 per cent. From January 1, 2008 to June 30, 2009, TransCanada's ownership interest in PipeLines LP was 32.1 per cent.

(5) Portland's results reflect TransCanada's 61.7 per cent ownership interest.

(6) Represents General, Administrative and Support Costs associated with certain of the Company's pipelines, including $17 million for Keystone.

(7) Non-Controlling Interests reflects Comparable EBITDA for the portions of PipeLines LP and Portland not owned by TransCanada.

(8) The Company recorded a valuation provision of $146 million for its advances to the APG for the MGP, which is discussed further under the heading Opportunities and Developments in the Natural Gas Pipelines section in this MD&A.

(9) As a result of PipeLines LP issuing common units to the public in 2009, 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.

(10) GTN and Portland received shares of Calpine with an initial value of $154 million and $103 million, respectively, as a result of the bankruptcy distributions with Calpine. These shares were subsequently sold for an additional gain of $22 million.

Natural Gas Pipelines generated Comparable EBIT of $1,938 million in 2010 compared to $2,063 million in 2009. Comparable EBIT in 2010 excluded a $146 million valuation provision for the Company's advances to the APG for the MGP. Comparable EBIT in 2009 excluded the $29 million dilution gain resulting from TransCanada's reduced interest in PipeLines LP, which occurred as a result of the public issuance of common units by PipeLines LP in November 2009. Comparable EBIT in 2008 was $2,030 million excluding the $279 million of gains received by Portland and GTN from the bankruptcy distributions with Calpine and the $17 million of proceeds received by GTN from a lawsuit settlement with a software supplier.

Wholly Owned Canadian Natural Gas Pipelines Net Income

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Canadian Mainline	**267**	273	278
Alberta System	**198**	168	145
Foothills	**27**	23	24

NATURAL GAS PIPELINES FINANCIAL ANALYSIS

Canadian Mainline The Canadian Mainline is regulated by the NEB under the *National Energy Board Act* (Canada). The NEB sets tolls that provide TransCanada with the opportunity to recover the costs of transporting natural gas, including a return on average investment base. The Canadian Mainline's EBITDA and net income are affected by changes in investment base, the rate of return on common equity (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 through 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 established certain elements of the Canadian Mainline's fixed OM&A costs for each of the five years. The variance between actual and agreed-upon OM&A costs accrued entirely to TransCanada from 2007 to 2009, and was shared equally between TransCanada and its customers in 2010, and will be shared equally in 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 TransCanada and its customers. In 2009, an adjustment charge account was established under a settlement with stakeholders and approved by the NEB to reduce tolls in 2010. In accordance with the terms of the settlement, balances in an adjustment charge account in any given year will be amortized at the composite depreciation rate and included in tolls commencing the following year.

Net income of $267 million in 2010 was $6 million lower than $273 million in 2009. The decrease was primarily the result of lower OM&A savings as a result of cost-sharing with customers and an ROE of 8.52 per cent in 2010 compared to 8.57 per cent in 2009. Net income in 2009 was $5 million lower than $278 million in 2008 as a result of a lower average investment base and lower ROE of 8.57 per cent in 2009 compared to 8.71 per cent in 2008.

Canadian Mainline's Comparable EBITDA of $1,054 million in 2010 was $79 million lower than $1,133 million in 2009, primarily due to reduced revenues as a result of lower income taxes and financial charges in the 2010 tolls, which are recovered on a flow-through basis and do not affect net income. The decrease in financial charges was primarily due to higher-cost debt that matured in 2009 and early 2010. The lower income taxes in 2010 were primarily due to the adjustment charge that decreased taxable income. Comparable EBITDA in 2009 declined $8 million from $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 2009 revenues was partially offset by higher OM&A cost savings and recovery of higher depreciation.

Alberta System The Alberta System is also regulated by the NEB, which approves the Alberta System's tolls and revenue requirement. The Alberta System's EBITDA and net income are 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 currently operates under the 2010 - 2012 Revenue Requirement Settlement approved by the NEB in September 2010. In October 2010, the NEB approved TransCanada's application to establish final tolls for 2010. In 2008 and 2009, the Alberta System operated under the 2008 - 2009 Revenue Requirement Settlement approved by the Alberta Utilities Commission (AUC) in December 2008. The Alberta System was regulated by the AUC until April 2009.

The 2010 - 2012 Revenue Requirement Settlement established an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and agreed-to OM&A costs accrue to TransCanada over the three-year term. All other cost elements of the revenue requirement are treated on a flow-through basis.

The 2008 - 2009 Revenue Requirement Settlement established fixed amounts for ROE, income taxes and certain OM&A costs. Variances between actual costs and those agreed to in the settlement accrued to TransCanada, 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-though basis.

The Alberta System's net income of $198 million in 2010 was $30 million higher than $168 million in 2009. The increase reflects an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 and a higher average investment base, partially offset by lower incentive earnings. Net income in 2009 was $23 million higher than $145 million in 2008 primarily due to higher settlement earnings and a higher average investment base in 2009. The increased average investment base reflected capital expenditures from 2008 to 2010 to expand capacity in response to growing customer demand for service.

The Alberta System's Comparable EBITDA of $742 million in 2010 was $14 million higher than $728 million in 2009. The increase reflects an ROE of 9.70 per cent on 40 per cent deemed common equity in 2010 and a higher average investment base, partially offset by lower incentive earnings, and lower financial charges and depreciation recovered on a flow-through basis. Comparable EBITDA in 2009 was $36 million higher than $692 million in 2008 primarily due to increased settlement earnings and a higher average investment base as well as higher revenues as a result of the recovery of higher financial charges, partially offset by lower income taxes.

Foothills Net income and Comparable EBITDA from Foothills increased $4 million and $3 million, respectively, in 2010 from 2009 primarily due to a Foothills 2010 settlement agreement, which established an ROE of 9.70 per cent on deemed common equity of 40 per cent for 2010 through 2012. Results in 2009 and 2008 were based on the NEB ROE formula of 8.57 per cent and 8.71 per cent, respectively, on deemed common equity of 36 per cent.

Other Canadian Natural Gas Pipelines Comparable EBITDA from Other Canadian Natural Gas Pipelines was $50 million in 2010 compared to $59 million in 2009. The decrease was primarily due to an adjustment in 2009 related to the NEB decision reached in March 2009 on Trans Québec and Maritimes' (TQM) cost of capital for 2007 and 2008. Comparable EBITDA in 2009 increased $9 million from $50 million in 2008, primarily due to the adjustment in 2009.

ANR American Natural Resources' (ANR) natural gas storage and transportation services are regulated by the U.S. Federal Energy Regulatory Commission (FERC) and services are provided under 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 rates were established pursuant to a settlement approved by the FERC and became effective beginning in 1997. ANR Storage Company's rates were established pursuant to a settlement approved by the FERC and became effective beginning in 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 case for new rates.

ANR's EBITDA is affected by the contracting and pricing of its existing transportation and storage capacity, expansion projects, delivered volumes and incidental natural gas sales, as well as by costs for providing various services, which include OM&A costs and property taxes. Due to the seasonal nature of its business, ANR's volumes and revenues are generally higher in the winter months.

ANR's Comparable EBITDA in 2010 was US$314 million, an increase of US$14 million compared to US$300 million in 2009, primarily due to lower OM&A costs, partially offset by lower contracted firm long-haul transportation sales and storage revenues as higher regional storage inventories and marginal supply from the U.S. Gulf Coast negatively affected transportation rates and demand for natural gas. Comparable EBITDA in 2009 decreased US$27 million compared to US$327 million in 2008. The decrease was due to lower incidental natural gas sales and higher OM&A costs, partially offset by higher transportation and storage revenues resulting from expansion projects, increased utilization and favourable pricing on existing capacity.

GTN GTN is regulated by the FERC and is operated in accordance with 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. These rates were effective January 1, 2007. GTN is permitted to discount or negotiate these rates on a non-discriminatory basis. 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 that are to be in effect no later than January 1, 2014.

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, which include OM&A costs and property taxes.

GTN's Comparable EBITDA was US$171 million in 2010, an increase of US$1 million compared to US$170 million in 2009. The increase was primarily due to lower OM&A costs and incremental proceeds accrued in 2010 relating to bankruptcy distributions with Calpine, partially offset by the impact of selling North Baja to PipeLines LP in July 2009 and the write-off of costs in 2010 related to an unsuccessful information systems project. Comparable EBITDA in 2009 decreased US$15 million, compared to US$185 million in 2008, primarily due to the sale of North Baja to PipeLines LP.

Other U.S. Natural Gas Pipelines Comparable EBITDA for the remainder of the U.S. Natural Gas Pipelines was US$481 million in 2010 and US$488 million in 2009. The decrease was primarily due to lower Great Lakes revenues, and higher general, administrative and support costs primarily related to the start-up of Keystone. Partially offsetting these decreases were increased revenues from Northern Border and higher PipeLines LP earnings in 2010 primarily due to its acquisition of North Baja in July 2009. Comparable EBITDA in 2009 increased US$24 million from US$464 million in 2008, primarily due to PipeLines LP's acquisition of North Baja.

Business Development Natural Gas Pipelines' Business Development Comparable EBITDA loss in 2010 was consistent with 2009. Comparable EBITDA losses increased to $62 million in 2009 from $37 million in 2008 primarily due to higher business development costs associated with the Alaska Pipeline Project.

Depreciation and Amortization Depreciation and Amortization for Natural Gas Pipelines was $977 million in 2010, a decrease of $53 million from $1,030 million in 2009. The decrease was primarily due to a weaker U.S. dollar in 2010 and lower depreciation for Great Lakes as a result of the lower depreciation rate in its rate settlement. Depreciation and Amortization increased $41 million to $1,030 million in 2009 from $989 million in 2008 primarily due to the stronger U.S. dollar in 2009.

NATURAL GAS PIPELINES OPPORTUNITIES AND DEVELOPMENTS

Canadian Mainline and Alberta System 2011 Tolls In December 2010, the NEB denied TransCanada's initial interim application for 2011 tolls on the Canadian Mainline and Alberta System, which was based on a new three-year agreement with the Canadian Association of Petroleum Producers (CAPP) and was supported by CAPP and certain other stakeholders. In its decision, the NEB concluded that it was not prepared to implement significant changes to the established Canadian Mainline toll design and method of allocating costs on an interim basis, and established Canadian Mainline 2010 tolls as interim tolls for 2011. As a result, TransCanada filed for revised interim tolls on January 25, 2011 based on the existing 2007 - 2011 settlement with customers. If approved, the revised interim tolls will allow for collection of revenues that will more closely reflect TransCanada's costs and forecast throughput in 2011. TransCanada is continuing its discussions with stakeholders with the intent of increasing the level of support for a potential settlement and expects to file a subsequent application for final 2011 tolls for the Canadian Mainline.

Interim tolls for 2011 on the Alberta System were established based on the provisions of the Alberta System 2010 - 2012 Revenue Requirement Settlement approved by the NEB in 2010. TransCanada expects to file for final 2011 tolls on the Alberta System that would reflect the outcome of further discussions with stakeholders with respect to the 2011 tolls and commercial integration of the ATCO Pipelines system.

Canadian Mainline In 2010, the Canadian Mainline continued to base its return on the NEB's ROE formula in accordance with the terms of the 2007 - 2011 tolls settlement. The 2010 calculated ROE for the Canadian Mainline was 8.52 per cent, a decrease from 8.57 per cent in 2009. The NEB formula ROE in 2011 is 8.08 per cent and, pending the outcome of further discussions with stakeholders, this ROE is applicable for 2011 tolls.

Annual tolls on the Canadian Mainline are partially based on projected throughput volumes for the year. Throughput volumes for 2010 were lower than those projected when setting tolls for the year and, as a result, amounts collected through tolls were approximately 15 per cent less than anticipated in 2010. This shortfall is deferred as a Regulatory Asset for accounting purposes as it is expected to be collected in future tolls under the framework regulated by the NEB.

With the objective of maintaining markets and competitive position, TransCanada conducted two open seasons in 2010 to transport Marcellus shale gas volumes on the Canadian Mainline. These open seasons resulted in the execution of precedent agreements in January 2011 to transport a total of approximately 230,000 gigajoules of natural gas per day to eastern Canadian markets. TransCanada is assessing the facilities required to provide the requested service and will begin the work necessary to support a regulatory application in the near future.

Alberta System In September 2010, the NEB approved the Alberta System's 2010 - 2012 Revenue Requirement Settlement Application. The settlement incorporates a return of 9.70 per cent on 40 per cent deemed common equity and included an annual fixed amount of $174 million for certain OM&A costs. Variances between actual and recoverable OM&A costs accrue to TransCanada over the three-year term. All other cost elements of the revenue requirement are treated on a flow-through basis.

In August 2010, the NEB approved the Company's application for the Alberta System's Rate Design Settlement and the commercial integration of the ATCO Pipelines system with the Alberta System. This approval permits the provision of streamlined natural gas transmission service to Alberta System customers under a new rate structure that reflects the business environment. TransCanada expects commercial and operational integration of the ATCO Pipelines system and the Alberta System to be completed in third quarter 2011.

In October 2010, the NEB approved final rates for the Alberta System that reflect the 2010 - 2012 Revenue Requirement Settlement and the Rate Design Settlement. These settlements are the result of many months of collaborative work with stakeholders.

In March 2010, the final phase of the NCC natural gas pipeline was completed. The NCC consists of a 300 km (186 miles) pipeline and associated compression facilities on the northern section of the Alberta System. The NCC provides capacity to accommodate increasing natural gas supply in northwestern Alberta and northeastern B.C., increasing natural gas demand within Alberta and deliveries of natural gas to Canadian and U.S. markets. The NCC is also expected to materially reduce the quantity of fuel gas consumed by the Alberta System. This project was completed on schedule and under budget at a total capital cost of approximately $800 million.

In December 2010, the Groundbirch pipeline was completed and put in service. Groundbirch extends the Alberta System into northeastern B.C. and connects it to natural gas supplies in the Montney shale gas formation. The project was completed on schedule and under budget at a total capital cost of approximately $155 million. Groundbirch has firm transportation contracts for 1.24 Bcf/d by 2014.

In January 2011, the NEB approved construction of the Horn River pipeline, which will connect new shale gas supply in the Horn River basin north of Fort Nelson, B.C. to the Alberta System. The pipeline, costing approximately $310 million, is scheduled to be operational in second quarter 2012 and has commitments for contracted natural gas of approximately 634 million cubic feet per day (mmcf/d) by 2014.

TransCanada continues to advance further pipeline development in B.C. and Alberta to transport new gas supply. The Company has received requests for additional natural gas transmission service throughout the northwest portion of the Western Canada Sedimentary Basin (WCSB), including the Horn River and Montney areas of B.C. These new requests are expected to result in the need for further extensions and expansions of the Alberta System.

Bison Bison is a 487 km (303 miles) natural gas pipeline extending from the Powder River Basin in Wyoming and connecting to Northern Border in North Dakota. The pipeline has shipping commitments for approximately 407 mmcf/d and was placed in service in January 2011. The capital cost of Bison was US$630 million.

Mexico In 2010, TransCanada began construction on the US$360 million Guadalajara 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. Guadalajara is a natural gas pipeline of approximately 305 km (190 miles) extending from Manzanillo to Guadalajara. The pipeline has an expected in-service date of mid-2011 and was 70 per cent complete at December 31, 2010. TransCanada continues to pursue additional opportunities in Mexico, including the extension or expansion of existing assets.

Great Lakes In November 2009, the FERC issued an order instituting an investigation pursuant to Section 5 of the *Natural Gas Act* (Rate Proceeding). The FERC alleged, based on a review of certain historical information, that Great Lakes' revenues might substantially exceed its actual cost of service and, therefore, may be unreasonable. In July 2010, the FERC approved, without modification, a settlement reached among Great Lakes, active participants and the FERC trial staff establishing the terms pursuant to which all matters in the Rate Proceeding would be resolved. As approved, this settlement applies to all current and future shippers on the Great Lakes system.

Under the terms of the settlement, Great Lakes' reservation rates were reduced by eight per cent and annual depreciation expense for Great Lakes' transmission plant were decreased to a rate of 1.48 per cent from a rate of 2.75 per cent. Depreciation rates for other assets decreased or remained unchanged. Rates for interruptible transportation services increased approximately 28 per cent. All terms of the settlement were effective May 1, 2010.

Under the terms of the settlement, Great Lakes' obligation to share interruptible transportation revenues with its shippers was eliminated effective May 1, 2010. Great Lakes also agreed to a new revenue-sharing provision whereby it will share with qualifying shippers 50 per cent of any qualifying revenues collected in excess of US$500 million between November 1, 2010 and October 31, 2012.

ANR In 2010, ANR connected new sources of natural gas supply from emerging production plays located in the Texas and Oklahoma panhandle regions and connected with new pipelines from shale gas supply in the U.S midcontinent. ANR is focused on attracting and connecting to additional natural gas supply directly or through new pipeline interconnects and on connecting to new or growing markets, particularly in the U.S. Midwest where natural gas-fired electric generation demand is expected to increase over the next several years.

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$40 million to US$50 million, mainly to replace, repair and abandon capital assets, including the estimated cost to abandon an offshore platform. Since September 2008, related capital expenditures of US$13 million (2009 US$11 million) and OM&A costs of US$9 million (2009 US$7 million) have been incurred. The remaining costs are expected to be incurred primarily in 2011 and 2012. Service on the offshore facilities and related throughput volumes are at pre-hurricane levels.

TQM In December 2010, the NEB approved TQM's final tolls for 2010 and interim tolls for 2011. These final and interim tolls reflect the terms of an NEB-approved multi-year settlement with TQM's interested parties regarding its annual revenue requirement for 2010 to 2012. The settlement includes an annual revenue requirement comprising fixed and flow-through components. The fixed component includes certain OM&A costs, return on rate base, depreciation and municipal taxes, with variances from actual costs accruing to TQM. In June 2010, the NEB approved TQM's final 2009 tolls based on a 6.4 per cent after-tax weighted average cost of capital on rate base and all the cost components in an NEB-approved three-year partial settlement for 2007 to 2009.

Alaska Pipeline Project The proposed Alaska Pipeline Project is a 4.5 Bcf/d natural gas pipeline extending 2,737 km (1,700 miles) from a proposed new natural gas treatment plant at Prudhoe Bay, Alaska to Alberta. The pipeline would 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 filed by TransCanada included provisions to expand capacity to 5.9 Bcf/d through the addition of compressor stations in Alaska and Canada. The estimated capital cost for the project is an increase over previous 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. TransCanada has also proposed an alternate pipeline from Prudhoe Bay to Valdez, Alaska to supply LNG markets. The estimated capital cost of the alternate pipeline is US$20 billion to US$26 billion. TransCanada has entered into an agreement with ExxonMobil to jointly advance the project. A joint project team is developing the engineering, environmental, aboriginal relations and commercial components of the project.

The State of Alaska has issued TransCanada a license to construct the Alaska Pipeline Project under the *Alaska Gasline Inducement Act* (AGIA). The state determined that TransCanada's application to construct a pipeline under the AGIA was the only proposal that met all of the state's requirements. Under the AGIA, the State of Alaska has agreed to reimburse a share of TransCanada's eligible pre-construction costs, as they are incurred, subject to approval by the state, to a maximum of US$500 million. The State of Alaska reimbursed up to 50 per cent of the eligible costs incurred prior to the close of the first binding open season on July 30, 2010. Commencing July 31, 2010, the state began reimbursing up to 90 per cent of the eligible costs. The reimbursements and project-applicable expenses are shared proportionately with ExxonMobil. In 2010, the Company expensed $34 million related to the project.

On July 30, 2010, the Alaska Pipeline Project concluded its initial open season. The project team continues to work with shippers to resolve the conditions under its control.

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 would have a capacity of up to 1.3 Bcf/d of natural gas and would be a 50/50 joint venture between GTN and Northwest Natural Gas Co. In May 2010, an underpinning shipper filed a bankruptcy proceeding and subsequently terminated its transportation agreement with Palomar. The partners of Palomar continue to support the project and are engaged in discussions with potential shippers to secure additional shipping commitments for the proposed pipeline.

Mackenzie Gas Project The MGP is a proposed 1,196 km (743 miles) natural gas pipeline extending from a point near Inuvik, Northwest Territories to the northern border of Alberta, where it would connect to the Alberta System.

TransCanada's involvement with the MGP arises from a 2003 agreement between the Mackenzie Valley APG and the MGP, under which TransCanada agreed to finance the APG's one-third share of the pre-development costs associated with the project. Under the terms of certain MGP agreements, TransCanada holds an option to acquire up to five per cent equity ownership in the MGP at the time of the decision to construct it. In addition, TransCanada gained 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.

At December 31, 2010, the Company had advanced $146 million (2009 $143 million) on behalf of the APG. These advances constituted a loan to the APG, which would become repayable only after the natural gas pipeline commenced commercial operations. If the project does not proceed, TransCanada has no recourse against the APG for recovery of advances made.

The MGP proponents continue to pursue the required regulatory approvals for the project and the Canadian government's support of an acceptable fiscal framework. In December 2010, the NEB released a decision granting approval of the project's application for a Certificate of Public Convenience and Necessity. The approval contained 264 conditions including the requirement to file an updated cost estimate and report on the decision to construct by the end of 2013 and, further, that construction must commence by December 31, 2015.

Nevertheless, uncertainty persists with respect to the project's ultimate commercial structure and fiscal framework, the timeframes under which the project would proceed and if and when the Company's advances to the APG will be repaid. Accordingly, at December 31, 2010, TransCanada recorded a valuation provision for its $146 million loan to the APG. Future amounts advanced to the APG in furtherance of the MGP will be expensed. TransCanada remains committed to advancing the project.

Natural Gas Supply, Markets and Competition TransCanada faces competition at both the supply and market ends of its natural gas pipeline systems. This competition comes from other natural gas pipelines accessing supply basins, including the WCSB, and markets served by TransCanada'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 has increased in the U.S., driven primarily by shale gas, while WCSB and other natural gas basin production has declined. 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-haul, long-term firm contracted capacity and a shift to shorter-distance, short-term firm and interruptible contracts on natural gas pipelines.

Although TransCanada has diversified its natural gas supply sources, 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 60 trillion cubic feet and a reserves-to-production ratio, based on these established reserves, of approximately 11 years at current levels of production. The reserves-to-production ratio is a measure of drilling and production activity that can increase or deplete reserves. Historically, this factor has been unchanged at approximately nine years. More recently, it has increased to 11 years as production from the WCSB has declined due to reduced drilling activity in the basin. The reduced drilling activity is a result of lower prices, higher supply costs 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 increase and finding and development costs continue to improve. As part of the Alberta government's competitiveness review, the existing oil and gas royalty framework was substantially revamped. These changes are expected to increase investment in the WCSB, which should also support increased activity levels. TransCanada expects there will be excess natural gas pipeline capacity from the WCSB to markets outside Alberta for the foreseeable future as a result of capacity expansions on natural gas pipelines over the past decade, competition from other pipelines and supply basins, and significant growth in natural gas consumption within Alberta driven primarily by oil sands and electricity generation requirements.

TransCanada's Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas processing plants in Western Canada to domestic and export markets. Despite reduced overall drilling levels, increased drilling rates in certain areas of the WCSB have resulted in the need for new natural gas transmission infrastructure. Drilling activity has increased in northwestern Alberta and northeastern B.C. as producers develop projects to access deeper multi-zone reserves, unconventional gas shale and tight sands utilizing horizontally-drilled wells in combination with multi-stage hydraulic fracturing stimulation techniques. Recently, shale gas production in northeastern B.C. has emerged as a significant natural gas supply source. TransCanada forecasts approximately 5 Bcf/d of total production from the Montney and Horn River shale gas sources by 2020, however, achieving this level will depend on natural gas prices as well as producer economics in the basin. The production from these two natural gas zones is approximately 1 Bcf/d. TransCanada recently commissioned the Groundbirch pipeline, its first B.C. pipeline extension to serve the Montney shale gas formation. In addition, the Company received approval in January 2011 to construct a major extension of its Alberta System that will allow emergent unconventional B.C. gas production from the Horn River shale gas formation to be transported to markets served by TransCanada's pipeline systems.

Demand for WCSB-sourced natural gas in Eastern Canada and the U.S. Northeast decreased in 2010, largely as a result of a diversification of supply sources. However, demand for natural gas in TransCanada's key eastern markets served by the Canadian Mainline is expected to increase over time, particularly to meet the expected growth in natural gas-fired power generation. There are opportunities to increase market share in Canadian domestic and U.S. export markets, however, TransCanada expects to continue to face 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 TransCanada'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 reductions in both volumes and distance transported 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 U.S. Gulf Coast and midcontinent regions which are also served by competing interstate and intrastate natural gas pipelines. The U.S. Gulf Coast is highly competitive given its extensive natural gas pipeline network. ANR is one of many pipelines competing for new and existing production in this region. ANR must also compete for interconnects with and supply from pipelines originating within the growing U.S. midcontinent shale gas formations and the Rocky Mountain production regions.

ANR competes for market share with other natural gas pipelines and storage operators in its primary markets in the U.S. Midwest. Lower natural gas prices could reduce drilling activity and reduce the supply growth that has been fuelling the expansion of pipeline infrastructure in the U.S. midcontinent. As transportation capacity becomes more abundant, lower natural gas prices and supply could negatively affect the value of pipeline capacity. ANR's natural gas storage is primarily contracted on a relatively short-term basis and the value of storage services is based on market conditions, which could become unfavourable resulting in reduced rates and terms.

GTN is primarily supplied with natural gas from the WCSB and competes with other interstate pipelines providing natural gas transportation services to markets in the U.S. Pacific Northwest, California and Nevada. These markets also have access to supplies from natural gas basins in the Rocky Mountains and the U.S. Southwest. Historically, natural gas supplies from the WCSB have been competitively priced against supplies from the other regions serving these markets. Increased competing supply sources could negatively affect the transportation value on GTN. Pacific Gas and Electric Company, GTN's largest customer, received California Public Utilities Commission approval to commit to capacity on a competing pipeline project out of the Rocky Mountain basin to the California border. The owner of this competing pipeline has announced it is expected to be in service in 2011.

Regulatory Risk Regulatory decisions continue to have an impact on the financial returns from existing investments in TransCanada's Canadian natural gas pipelines and are expected to have a similar impact on financial returns from future investments. Through rate applications and negotiated settlements, TransCanada has been able to improve the financial returns of its Canadian natural gas pipeline and their capital structures.

Regulations and decisions issued by U.S. regulatory bodies, particularly the FERC, Environmental Protection Agency (EPA) and Department of Transportation, may have an impact on the financial performance of TransCanada's U.S. pipelines. TransCanada continually monitors existing and proposed regulations to determine their possible impact on its U.S. pipelines.

Throughput Risk As transportation contracts expire, TransCanada expects its U.S. natural gas pipelines to become more exposed to the risk of reduced throughput and their revenues to become more likely to experience increased variability. Throughput risk is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline competition and pricing of alternative fuels.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Natural Gas Pipelines business.

NATURAL GAS PIPELINES OUTLOOK

The Company expects demand for natural gas in North America to increase in the long term, although demand growth is expected to continue to be relatively weak in 2011. TransCanada's Natural Gas Pipelines business will continue to focus on delivering natural gas to growing markets, connecting new supply and progressing development of new infrastructure to connect with natural gas from unconventional supplies such as shale gas, coalbed methane and LNG, and from the north.

Reduced throughput and greater use of shorter-distance transportation contracts are the primary factors that continue to put pressure on the Canadian Mainline to increase its tolls. This situation, coupled with the ongoing development and growth of competitive alternative natural gas supply from infrastructure in U.S. shale gas regions, is increasing competitive pressures on the Canadian Mainline. In response, TransCanada continues to work closely with its stakeholders, examining 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. TransCanada is also pursuing the connection of new sources of U.S. natural gas supply from the Marcellus shale gas formation to the Canadian Mainline infrastructure to enhance its current markets and competitive position.

TransCanada 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.

Most of TransCanada's expansion plans in Canadian natural gas transmission are focused on the Alberta System. TransCanada 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., TransCanada expects unconventional production will continue to be developed from shale gas formations in eastern Texas, northwestern Louisiana, Arkansas, southwestern Oklahoma and the Appalachian Mountain region. Production focus has shifted in the near term toward more oil and hydrocarbon-rich production, which is expected to increase natural gas supply in Texas and North Dakota. Supply from coalbed methane and tight gas sands in the Rocky Mountain region is also expected to grow. The resulting anticipated growth in U.S. supply should provide additional opportunities for TransCanada's U.S. pipelines.

Earnings Canadian Natural Gas Pipelines' earnings are affected by changes in investment base, ROE, capital structure and terms of toll settlements as approved by the NEB, with the most significant variables being ROE, capital structure and investment base. The Company expects continued growth of the Alberta System investment base as new supply in northeastern B.C. continues to be developed and connected to the Alberta System. TransCanada 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 as annual depreciation outpaces capital investment. A net decline in the average investment base would have the effect of reducing year-over-year earnings from these assets. Under the current regulatory model, earnings from Canadian natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contract levels.

The in service of Bison in January 2011 and the expected in service of Guadalajara in mid-2011 will positively impact earnings of U.S. Natural Gas Pipelines. The ability to recontract available capacity at attractive rates 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 TransCanada's U.S. pipelines. EBIT from U.S. Natural Gas Pipelines' operations is also affected by the level of OM&A costs, regulatory decisions and changes in foreign currency exchange rates.

In addition, Natural Gas Pipelines' EBIT is expected to be affected by costs to develop new pipeline projects, including the Alaska Pipeline Project.

Capital Expenditures Total capital spending for natural gas pipelines was $1.2 billion in 2010. Capital spending for the Company's wholly owned pipelines is expected to be approximately $1.1 billion in 2011.

NATURAL GAS THROUGHPUT VOLUMES

(Bcf)	**2010**	2009	2008
Canadian Mainline[(1)]	**1,666**	2,030	2,173
Alberta System[(2)]	**3,447**	3,538	3,800
ANR	**1,589**	1,575	1,619
Foothills	**1,446**	1,205	1,292
Northern Border[(3)]	**902**	706	839
Great Lakes	**804**	727	784
GTN	**802**	797	783
Iroquois	**343**	355	376
TQM	**151**	164	170
Ventures LP	**144**	145	165
North Baja	**60**	96	104
Tamazunchale	**52**	54	53
Gas Pacifico	**51**	62	73
Portland	**36**	37	50
Tuscarora[(3)]	**35**	34	30
TransGas	**30**	28	26

(1) Canadian Mainline's throughput volumes reflect physical deliveries to domestic and export markets. Customer contracting patterns have changed in recent years therefore the Company uses physical deliveries to measure system utilization. Canadian Mainline physical receipts originating at the Alberta border and in Saskatchewan in 2010 were 1,228 Bcf (2009 1,579 Bcf; 2008 1,898 Bcf).

(2) Field receipt volumes for the Alberta System in 2010 were 3,471 Bcf (2009 3,578 Bcf; 2008 3,843 Bcf).

(3) Throughput volumes for Northern Border and Tuscarora reflect scheduled deliveries. Throughput volumes in previous years reflected physical deliveries.

OIL PIPELINES

OIL PIPELINES HIGHLIGHTS

- The Company invested $2.7 billion in 2010 to advance Keystone.
- The first phase of Keystone extending from Hardisty, Alberta to Wood River and Patoka in Illinois began operating at a low operating pressure in June 2010.
- The second phase extending Keystone from Steele City, Nebraska to Cushing, Oklahoma was placed in service at the beginning of February 2011.

OIL PIPELINES FINANCIAL ANALYSIS

Although the first phase of Keystone extending from Hardisty, Alberta to Wood River and Patoka in Illinois commenced commercial operations in June 2010, cash flows related to Keystone, other than general, administrative and support costs, were capitalized during 2010. As a condition of the NEB's approval to begin operations, Wood River/Patoka was operating at a reduced maximum operating pressure (MOP) on the Canadian conversion segment of the pipeline, which did not allow the pipeline to run at design pressure and reduced throughput capacity below the initial nominal capacity of 435,000 Bbl/d. After additional in-line inspections were completed, the NEB removed the MOP restriction in December 2010 and the required operational modifications were completed in late January 2011. As a result, the system began operating at design pressure and the Company commenced recording EBITDA for Keystone at the beginning of February 2011.

OIL PIPELINES OPPORTUNITIES AND DEVELOPMENTS

Keystone The Cushing Extension extends the pipeline to Cushing, Oklahoma and increases nominal capacity to 591,000 Bbl/d if design capacity is achieved. The extension began commissioning in late 2010 and commenced commercial in service at the beginning of February 2011.

After an open season conducted in 2008, Keystone secured additional firm, long-term shipper contracts to expand and extend the system. With these commitments, Keystone filed the necessary regulatory applications in Canada and the U.S. for approval to construct and operate the U.S. Gulf Coast Expansion from Western Canada to the U.S. Gulf Coast, which would provide additional pipeline capacity. In March 2010, the NEB approved the application for the new Canadian facilities required for the U.S. Gulf Coast Expansion. In April 2010, the Department of State, the lead agency for U.S. federal regulatory approvals, issued a Draft Environmental Impact Statement which concluded that the U.S. Gulf Coast Expansion would have limited environmental impact. The regulatory process conducted by the Department of State is continuing within a heightened political environment and opposition to the project has been expressed. However, the Company expects a decision regarding final regulatory approvals in mid to late 2011. Construction on the U.S. Gulf Coast Expansion is expected to begin shortly thereafter.

The capital cost of Keystone, including the U.S. Gulf Coast Expansion, is estimated to be approximately US$13 billion. The US$1 billion increase from the previously estimated capital cost of approximately US$12 billion reflects currency translation, an increase in the actual cost incurred bringing the Wood River/Patoka and Cushing Extension phases to commercial in service and an increase in estimated capital cost associated with the U.S. Gulf Coast Expansion resulting from scope changes, evolving regulatory requirements and permitting delays. At December 31, 2010, US$7.4 billion had been invested, including US$1.4 billion related to the U.S. Gulf Coast Expansion. The remaining US$5.6 billion, US$1.2 billion of which has already been committed, is expected to be invested between now and the in-service date of the expansion, which is expected in 2013. Capital costs related to the construction of Keystone are subject to capital cost risk- and reward-sharing mechanisms with Keystone's long-term committed shippers.

In August 2009, TransCanada purchased ConocoPhillips' remaining interest in Keystone. The purchase gave TransCanada 100 per cent ownership of Keystone.

Three entities, each of which had entered into Transportation Service Agreements for the Cushing Extension, have filed separate Statements of Claim against certain of TransCanada's Keystone subsidiaries in the Alberta Court of Queen's Bench, seeking declaratory relief, or alternatively, damages in varying amounts. One of the claims has been discontinued on a without-cost and without-liability basis. The Company believes the remaining claims to be without merit and will vigorously defend against them.

Marketlink Projects The Company is pursuing opportunities to transport growing Bakken shale crude oil production from the Williston Basin in Montana and North Dakota to major U.S. refining markets. Following an open season conducted in the second half of 2010, the Company secured firm, five-year shipper contracts totalling 65,000 Bbl/d for its proposed Bakken Marketlink project, which would transport U.S. crude oil from Baker, Montana to Cushing on facilities that form part of the Keystone U.S. Gulf Coast Expansion. With these commitments, TransCanada will file for the necessary regulatory approvals in the U.S. to construct and operate the Bakken Marketlink project. The capital cost of the incremental facilities is expected to be approximately US$140 million and commercial in service is anticipated in 2013.

Following an open season conducted in the second half of 2010, the Company secured contractual support to proceed with the Cushing Marketlink project, which would transport up to 150,000 Bbl/d of crude oil from Cushing to the U.S. Gulf Coast on facilities that form part of the U.S. Gulf Coast Expansion. With these commitments, TransCanada will file for the necessary regulatory approvals in the U.S. to construct and operate the Cushing Marketlink project. Commercial in service is anticipated in 2013.

OIL PIPELINES BUSINESS RISKS

Crude Oil Supply, Markets and Competition Alberta produces approximately 80 per cent of the crude oil in the WCSB and is the primary source of crude oil supply for Keystone. In 2010, the WCSB produced an estimated 2.6 million Bbl/d, consisting of 1.1 million Bbl/d of conventional crude oil and condensate, and 1.5 million Bbl/d of Alberta oil sands crude oil. The production of conventional crude oil has been declining but has been offset by increases in production from the oil sands. The Alberta Energy Resources Conservation Board estimated in its June 2010 report that there are approximately 170 billion barrels of remaining established reserves in the Alberta oil sands.

In June 2010, CAPP forecast WCSB crude oil supply would increase to 3.1 million Bbl/d by 2015 and to 3.7 million Bbl/d by 2020, indicating future growth in Alberta crude oil production. CAPP estimated spending in the oil sands totalled $13 billion in 2010 and forecasts $15 billion of spending in 2011.

Keystone 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.

The Williston Basin, located primarily in North Dakota and Montana, is the primary source of crude oil supply for the Bakken Marketlink project. In 2010, the Williston Basin achieved production rates of nearly 400,000 Bbl/d. TransCanada forecasts production levels will reach approximately 550,000 Bbl/d by 2015 due to growth in Bakken shale oil production.

The Permian Basin, located primarily in western Texas, is the primary source of crude oil for the Cushing Marketlink project. Production in the Permian Basin connected to crude oil storage facilities at Cushing is 900,000 Bbl/d and has been growing by approximately three per cent per year since 2006.

The Bakken Marketlink and Cushing Marketlink projects have contracted a significant amount of capacity. Both projects would compete for spot market throughput with other crude oil pipelines in the Williston Basin, Rocky Mountain and U.S. midcontinent regions and for new long-term contracts as supply from connected basins increases.

The markets for crude oil served by TransCanada's Keystone oil pipeline are primarily refiners in the U.S. Midwest, midcontinent and Gulf Coast regions. TransCanada will compete with pipelines that deliver WCSB, Williston Basin and Permian Basin crude oil to these refiners 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, Midcontinent and Gulf Coast regions.

Regulatory Risk Regulations and decisions issued by Canadian and U.S. regulatory bodies, particularly the NEB, FERC, EPA and U.S. Department of Transportation, may have a significant impact on the approval, construction, timing and financial performance of TransCanada's crude oil pipelines. TransCanada continuously monitors existing and proposed regulations to determine their possible impact on its Oil Pipelines business.

TransCanada anticipates final U.S. regulatory approvals for the U.S. Gulf Coast Expansion in mid to late 2011. However, if the expansion project as currently proposed is denied regulatory approval, the Company would look to reconfigure all or part of the project and redeploy invested capital to other pipeline opportunities and expense any unmitigated amounts.

Throughput Risk Throughput risk for TransCanada's crude oil pipelines is dependent primarily on crude oil production levels, market competition for crude oil, refinery activity and variations in economic activity. As transportation contracts expire, TransCanada expects its crude oil pipelines to become more exposed to the risk of reduced throughput and revenues to become more likely to experience increased variability. To assist in managing this risk, TransCanada has contracted a significant portion of capacity. Uncontracted capacity is offered to the market on a spot basis, creating the potential for increased earnings.

Plant Availability Optimizing and maintaining plant availability is essential to the success of the oil pipelines business. TransCanada has a proven history of achieving high levels of performance through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through firm contracts with Keystone's shippers. In the event of a force majeure, Keystone will continue to receive payments for capacity from its firm contract shippers for a limited time. In the event of a loss of capacity that is not due to force majeure, the firm payments for capacity may be reduced by the extent of the reduced capacity. Unexpected plant outages, including unexpected delays in completing planned outages, could result in lower pipeline throughput, resulting in lower sales revenue, reduced capacity payments and margins, and increased maintenance costs.

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 Keystone's long-term committed shippers. 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 Keystone's Wood River/Patoka and Cushing Extension phases will be adjusted by a factor equal to 50 per cent of the percentage change in capital cost. Tolls on the U.S. Gulf Coast Expansion would be adjusted by a factor equal to 75 per cent of the percentage change in capital cost. Capital costs related to the construction of the Bakken Marketlink and Cushing Marketlink projects would not be subject to a capital cost risk- and reward-sharing mechanism with the shippers.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Oil Pipelines business.

OIL PIPELINES OUTLOOK

North American crude oil demand is expected to remain relatively unchanged in the long term while the availability of foreign sources of supply to North America declines. TransCanada's Oil Pipelines business will continue to focus on contracting and delivering growing crude oil supply to key U.S. markets.

Producers continue to develop new crude oil supply in Western Canada. Several Alberta oil sands projects recently completed or under construction will begin to produce crude oil or will increase crude oil production in 2011 and 2012. Alberta oil sands production is forecast to increase to 2.2 million Bbl/d by 2015 from 1.5 million Bbl/d in 2010 and total Western Canada crude oil supply is projected to grow over the same period to 3.1 million Bbl/d from 2.6 million Bbl/d. The primary market for new crude oil production extends from the U.S. Midwest to the U.S. Gulf Coast and contains a large number of refineries that are capable of handling 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 markets in the U.S. Gulf Coast. TransCanada will continue to pursue additional opportunities to transport crude oil from Alberta to U.S. markets.

Production in the Williston Basin is also growing and pipeline capacity in the region is constrained. Major markets for Williston Basin crude oil include the U.S. midcontinent and Midwest, with the U.S. Gulf Coast being a potential growth market. There are several competitive proposals to build take-away pipeline capacity for this region and TransCanada will continue to compete for additional opportunities to transport Williston Basin crude oil to U.S. markets.

Take-away capacity is constrained on the pipelines serving the crude oil storage facilities at Cushing. This situation periodically causes the price of West Texas Intermediate crude oil to be depressed relative to world prices. There are several competitive proposals to build take-away pipeline capacity from this region to the U.S. Gulf Coast. TransCanada will continue to compete for additional opportunities to transport Cushing crude oil to U.S. markets.

TransCanada will continue to focus on operational excellence and collaboration with all stakeholders to provide services that will increase the value of the Company's business.

Earnings TransCanada began recording EBITDA from the Wood River/Patoka and the Cushing Extension phases beginning in February 2011 when they commenced full operations. TransCanada expects earnings from its crude oil pipelines to increase through 2011, 2012 and 2013 as Keystone's expansion phases and the proposed Marketlink projects begin delivering crude oil. Based on current long-term commitments for Keystone, TransCanada expects to record annual EBITDA of approximately US$1.3 billion, commencing in 2013, assuming a full year of commercial operations servicing both the U.S. Midwest and Gulf Coast markets. If volumes were to increase to the full commercial design of the system, TransCanada would record annual EBITDA of approximately US$1.5 billion. In the future, Keystone capacity could be economically expanded in response to additional market demand.

Capital Expenditures Total capital spending for Keystone in 2010 was $2.7 billion. Capital spending for Keystone in 2011 is expected to be approximately $1.4 billion.

The following Energy assets are owned 100 per cent by TransCanada 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 TransCanada 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. TransCanada 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 TransCanada 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 TransCanada's adjacent facility, which produces thermal carbon black (a natural gas by-product).

BRUCE POWER Bruce Power is a nuclear generating facility located northwest of Toronto, Ontario. TransCanada owns 48.8 per cent of Bruce A, which has four 750 MW reactors. Two of these reactors are currently operating and the remaining two are being refurbished. TransCanada 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, combined-cycle power plant in Halton Hills, Ontario which began commercial operations in third quarter 2010.

PORTLANDS ENERGY A 550 MW natural gas-fired, combined-cycle power plant located in Toronto, Ontario. The plant is 50 per cent owned by TransCanada.

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 TransCanada. Three of the wind farms, Baie-des-Sables, Anse-à-Valleau and Carleton, are operating and have a total generating capacity of 320 MW. The two remaining wind farms, Gros-Morne and Montagne-Sèche, are under construction and will have 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 farm located in Kibby and Skinner Townships in Maine. The 66 MW second phase of Kibby Wind was placed in service in October 2010.

TC HYDRO TC Hydro has a total generating capacity of 583 MW and comprises 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. TransCanada owns 60 per cent of CrossAlta.

ENERGY HIGHLIGHTS

- Energy's comparable EBIT was $748 million in 2010, a decrease of $36 million from $784 million in 2009.

In 2010, the Company invested $1.1 billion in Energy capital projects, including:

- the 683 MW Halton Hills generating facility, which was fully commissioned in September 2010, on time and on budget;
- the second phase of the Kibby Wind farm, which was placed in service in October 2010 and included the installation of an additional 22 turbines, ahead of schedule and on budget; and
- the restart of Bruce A Units 1 and 2 as well as construction of Coolidge and the two remaining wind farms at Cartier Wind.

Successful installation of the last of the fuel channel assemblies (FCA) and significant staff demobilization at Bruce A Unit 2 was achieved.

Approximately 1,500 MW of generation capacity was under construction and in development at December 31, 2010, at an anticipated total capital cost of approximately $3.2 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		
Halton Hills	683	Natural gas
Bécancour	550	Natural gas
Cartier Wind(3)	365	Wind
Portlands Energy(4)	275	Natural gas
Grandview	90	Natural gas
	1,963	
Bruce(5)	2,480	Nuclear
	7,079	
U.S. Power		
Ravenswood	2,480	Natural gas/oil
TC Hydro	583	Hydro
OSP	560	Natural gas
Kibby Wind	132	Wind
	3,755	
Total Nominal Generating Capacity	10,834	

(1) Currently under construction.

(2) Represents TransCanada's 50 per cent share of the Sundance B power plant output.

(3) Represents TransCanada's 62 per cent share of the total 590 MW project, including 168 MW under construction.

(4) Represents TransCanada's 50 per cent share of the total 550 MW facility.

(5)

Represents TransCanada'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)*	**2010**	2009	2008
Canadian Power			
Western Power	**220**	279	510
Eastern Power[1]	**231**	220	147
Bruce Power	**298**	352	275
General, administrative and support costs	**(38)**	(39)	(39)
Canadian Power Comparable EBITDA[2]	**711**	812	893
Depreciation and amortization	**(242)**	(227)	(198)
Canadian Power Comparable EBIT[2]	**469**	585	695
U.S. Power (in U.S. dollars)			
Northeast Power[3]	**335**	210	256
General, administrative and support costs	**(32)**	(40)	(38)
U.S. Power Comparable EBITDA[2]	**303**	170	218
Depreciation and amortization	**(116)**	(92)	(38)
U.S. Power Comparable EBIT[2]	**187**	78	180
Foreign exchange	**7**	8	8
U.S. Power Comparable EBIT[2] (in Canadian dollars)	**194**	86	188
Natural Gas Storage			
Alberta Storage	**140**	173	152
General, administrative and support costs	**(8)**	(9)	(14)
Natural Gas Storage Comparable EBITDA[2]	**132**	164	138
Depreciation and amortization	**(15)**	(14)	(17)
Natural Gas Storage Comparable EBIT[2]	**117**	150	121
Business Development Comparable EBITDA and EBIT[2]	**(32)**	(37)	(52)
Energy Comparable EBIT[2]	**748**	784	952
Summary:			
Energy Comparable EBITDA[2]	**1,125**	1,131	1,210
Depreciation and amortization	**(377)**	(347)	(258)
Energy Comparable EBIT[2]	**748**	784	952
Specific items:			
Risk management activities	**(8)**	1	
Write-down of Broadwater LNG project costs			(41)

Energy EBIT[2]	**740**	785	911

(1) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 2008, respectively.

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

(3) Includes phase one and two of Kibby Wind, and Ravenswood effective October 2009, October 2010 and August 2008, respectively.

Energy's Comparable EBIT was $748 million in 2010 compared to $784 million in 2009 and $952 million in 2008. Comparable EBIT in 2010 and 2009 excluded net unrealized losses of $8 million and net unrealized gains of $1 million, respectively, from changes in the fair value of proprietary natural gas inventory in storage and certain risk management activities. TransCanada manages its proprietary Natural Gas Storage business by simultaneously entering 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. Fair value adjustments are recorded each period on proprietary natural gas inventory in storage and on the forward contracts, however, these adjustments are not representative of the amounts that will be realized on settlement. U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers and manages exposure to fluctuations in spot prices on these power sales either with the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins. These Natural Gas Storage and U.S. Power contracts provide effective economic hedges which effectively lock in a margin but do not meet the specific criteria required for hedge accounting treatment and, therefore, are recorded at their fair value based on forward market prices for the contracted month of delivery. These forwards are excluded in determining Comparable Earnings as their fair value is not representative of amounts that will be realized on settlement. Comparable EBIT in 2008 excluded the $41 million write-down of costs previously capitalized for the Broadwater LNG project.

ENERGY FINANCIAL ANALYSIS

Western Power As at December 31, 2010, 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 power purchase arrangements (PPA), 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, baseload, coal-fired generation 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 and most competitive power 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 whose capacity ranges from 27 MW to 165 MW. A portion of the expected output from the Western Power 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 TransCanada 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, Western Power had, as at December 31, 2010, fixed-price power sales contracts to sell approximately 7,400 gigawatt hours (GWh) in 2011 and 6,300 GWh in 2012.

Eastern Power Eastern Power owns approximately 2,000 MW of power generation capacity, including facilities under construction. Eastern Power's current operating power generation assets are Halton Hills, Bécancour, three Cartier Wind farms, Portlands Energy and Grandview.

Halton Hills was placed in service in September 2010 and provides power under a 20-year Clean Energy Supply contract with the Ontario Power Authority (OPA).

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 suspended since January 2008 as a result of an agreement entered into with Hydro-Québec. Under the agreement, TransCanada continues to receive payments similar to those that would have been received under the normal course of operation. Suspension of electricity generation at the Bécancour power facility is discussed further in the Energy Opportunities and Developments section in this MD&A.

Three of Cartier Wind's operating wind farms, Carleton, Anse-à-Valleau, and Baie-des-Sables, were placed in service in November 2008, 2007 and 2006, respectively. Output from these wind farms is supplied to Hydro-Québec under 20-year power purchase contracts.

Portlands Energy was placed in 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. TransCanada and Irving Oil are under a 20-year tolling arrangement, which expires in 2025, through which Irving Oil supplies fuel for the 90 MW plant and is contracted to purchase 100 per cent of the plant's heat and electricity output.

Eastern Power is focused on selling power under long-term contracts. In 2008, 2009 and 2010, all of Eastern Power sales volumes were sold under contract and are expected to continue to be 100 per cent sold under contract in 2011 and 2012.

Western and Eastern Canadian Power Comparable EBIT[1][2]

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Revenues			
Western power	**714**	788	1,140
Eastern power[2]	**330**	281	175
Other[3]	**84**	86	138
	1,128	1,155	1,453
Commodity purchases resold			
Western power	**(431)**	(451)	(517)
Other[3][4]	**(26)**	(26)	(64)
	(457)	(477)	(581)
Plant operating costs and other	**(220)**	(179)	(215)
General, administrative and support costs	**(38)**	(39)	(39)
Comparable EBITDA[1]	**413**	460	618
Depreciation and amortization	**(140)**	(138)	(124)
Comparable EBIT[1]	**273**	322	494

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

(2) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 2008, respectively.

(3) Includes sales of excess natural gas purchased for generation, sales of thermal carbon black and sales of sulphur in 2008. Effective January 1, 2010, the net impact of derivatives used to purchase and sell natural gas to manage Western and Eastern Power's assets is presented on a net basis in Other Revenues. Comparative results for 2009 and 2008 reflect amounts reclassified to Other Revenues from Other Commodity Purchases Resold.

(4) Includes the cost of excess natural gas not used in operations.

Western and Eastern Canadian Power Operating Statistics[1]

Year ended December 31	2010	2009	2008
Sales Volumes (GWh)			
Supply			
Generation			
Western Power	2,373	2,334	2,322
Eastern Power	2,359	1,550	1,069
Purchased			
Sundance A & B and Sheerness PPAs	10,785	10,603	12,368
Other purchases	429	529	970
	15,946	15,016	16,729
Sales			
Contracted			
Western Power	10,211	9,944	11,284
Eastern Power	2,375	1,588	1,232
Spot			
Western Power	3,360	3,484	4,213
	15,946	15,016	16,729
Plant Availability[2]			
Western Power[3]	95%	93%	87%
Eastern Power[4]	94%	97%	97%

(1) Includes Halton Hills, Portlands Energy and Carleton effective September 2010, April 2009 and November 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.

(3) Excludes facilities that provide power to TransCanada under PPAs.

(4) Bécancour has been excluded from the availability calculation, as power generation at the facility has been suspended since 2008.

Western Power's Comparable EBITDA of $220 million and Power Revenues of $714 million in 2010 decreased $59 million and $74 million, respectively, compared to 2009 primarily due to lower overall realized power prices. Realized prices were negatively affected by lower contracted prices in 2010 compared to 2009 due to the continued impact of the North American economic downturn and the timing of certain unplanned outages that occurred in 2010 during periods of high spot prices. Approximately 25 per cent of Western Power's sales volumes were sold in the spot market in 2010 compared to 26 per cent in 2009.

Eastern Power's Comparable EBITDA of $231 million and Power Revenues of $330 million in 2010 increased $11 million and $49 million, respectively, compared to 2009. These increases were primarily due to incremental earnings from Halton Hills and Portlands Energy, which went into service September 2010 and April 2009, respectively, partially offset by lower contracted revenue from the Bécancour facility. Results from Bécancour are consistent with the expected contracted earnings based on the original electricity supply contract with Hydro-Québec.

Plant Operating Costs and Other, which includes natural gas fuel consumed in power generation, of $220 million in 2010 increased $41 million from 2009 primarily due to incremental fuel consumed at Portlands Energy and Halton Hills.

Western Power's Comparable EBITDA of $279 million and Power Revenues of $788 million in 2009 decreased $231 million and $352 million, respectively, compared to 2008. The decrease was primarily due to lower overall realized

prices on reduced volumes of power sold as a result of the economic downturn. Western Power's Comparable EBITDA in 2008 included $23 million related to sulphur sales. Commodity Purchases Resold decreased $66 million in 2009 compared to 2008 primarily due to a reduction in volumes purchased and the expiry of certain retail contracts. Approximately 26 per cent of power 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 and Power Revenues of $281 million in 2009 increased $73 million and $106 million, respectively, compared to 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.

Other Revenues and Other Commodity Purchases Resold were $86 million and $26 million, respectively, in 2009 compared to $138 million and $64 million, respectively, in 2008. The decreases in 2009 reflect the lower price of natural gas purchased for operations but not used. Other Revenues in 2008 included $23 million related to sulphur sales.

Plant Operating Costs and Other, which includes natural gas fuel 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 plants operated with an average availability of approximately 95 per cent in 2010, 93 per cent in 2009 and 87 per cent in 2008. The increases in 2010 and 2009 were primarily due to the return to service of the Cancarb facility in April 2009.

Bruce Power Bruce Power is a nuclear power generation facility located northwest of Toronto, Ontario and comprises Bruce A and Bruce B. Bruce A has four 750 MW reactors, two of which are operating and two are being refurbished. The two units being refurbished are expected to resume commercial operations in first quarter and third quarter 2012. Bruce B has four operating reactors with a combined capacity of 3,200 MW. As at December 31, 2010, TransCanada 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 (2009 48.8 per cent; 2008 48.9 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 the Bruce Power Employee Investment Trust. Bruce A subleases Bruce A Units 1 to 4 from Bruce B. TransCanada, 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 TransCanada's proportionate share of the eight Bruce Power units, six of which were operating:

Bruce Power Results[1]
(TransCanada's proportionate share)

Year ended December 31 *(millions of dollars unless otherwise indicated)*	**2010**	2009	2008
Revenues[2]	**862**	883	785
Operating expenses	**(564)**	(531)	(510)
Comparable EBITDA[1]	**298**	352	275
Bruce A Comparable EBITDA[1]	**91**	48	78
Bruce B Comparable EBITDA[1]	**207**	304	197
Comparable EBITDA[1]	**298**	352	275
Depreciation and amortization	**(102)**	(89)	(74)
Comparable EBIT[1]	**196**	263	201
Bruce Power Other Information			
Plant availability[3]			
Bruce A	**81%**	78%	82%
Bruce B	**91%**	91%	87%
Combined Bruce Power	**88%**	87%	86%
Planned outage days			
Bruce A	**60**	56	91
Bruce B	**70**	45	100
Unplanned outage days			
Bruce A	**64**	82	27
Bruce B	**34**	47	65
Sales volumes (GWh)			
Bruce A	**5,026**	4,894	5,159
Bruce B	**8,184**	7,767	7,799
	13,210	12,661	12,958
Results per MWh			
Bruce A power revenues	**$65**	$64	$62
Bruce B power revenues[4]	**$58**	$64	$57
Combined Bruce Power revenues	**$60**	$64	$59
Percentage of Bruce B output sold to spot market[5]	**82%**	43%	33%

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

(2) Revenues include Bruce A fuel cost recoveries of $29 million in 2010 (2009 $34 million; 2008 $30 million). Revenues also include Bruce B unrealized losses of $6 million as a result of changes in the fair value of held-for-trading derivatives in 2010 (2009 $5 million gains; 2008 $2 million losses).

(3)

Plant availability represents the percentage of time in a year that the plant is available to generate power regardless of whether it is running.

(4) Includes revenues received under the floor price mechanism, from contract settlements and 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.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA decreased $54 million to $298 million in 2010 compared to 2009. Comparable EBITDA in 2010 included the positive net impact of a payment made in 2010 by Bruce B to Bruce A related to amendments made in 2009 to the agreements with the OPA. The net positive impact to TransCanada from the payment reflected TransCanada's higher percentage ownership in Bruce A.

TransCanada's proportionate share of Bruce A's Comparable EBITDA increased $43 million to $91 million in 2010 compared to 2009 primarily as a result of the payment received from Bruce B, lower operating expenses due to a decrease in outage days and higher volumes.

TransCanada's proportionate share of Bruce B's Comparable EBITDA decreased $97 million to $207 million in 2010 compared to 2009. The decrease was primarily due to lower realized prices resulting from expiration of fixed-price contracts at higher prices, the payment made to Bruce A and a higher annual lease expense in 2010, partially offset by higher volumes. Provisions in the lease agreement with Ontario Power Generation allow for a reduction in the annual lease expense if the annual average Ontario spot price for electricity is less than $30 per megawatt hour (MWh). No lease expense reduction was available in 2010 while lease expense was reduced in 2009. The annual average Ontario spot price was $36.25 per MWh in 2010 compared to $29.52 per MWh in 2009 and $48.83 per MWh in 2008.

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. In both 2010 and 2009, no amounts recorded in revenue were repaid. Bruce B did not recognize into revenue any of the support payments received under the floor price mechanism in 2008 as the average spot price exceeded the floor price.

Bruce Power's Depreciation and Amortization increased $13 million in 2010 compared to 2009 and $15 million in 2009 compared to 2008 primarily due to capital additions.

TransCanada's proportionate share of Bruce Power's Comparable EBITDA of $352 million in 2009 increased $77 million compared to 2008 as a result of higher realized prices and reduced annual lease expense, partially offset by lower volumes and higher operating expenses for Bruce A.

TransCanada's proportionate share of Bruce Power's generation in 2010 increased to 13,210 GWh compared to 12,661 GWh in 2009, partially due to periods in 2009 when the Independent Electricity System Operator (IESO) curtailed certain units at Bruce Power to address surplus baseload 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 88 per cent in 2010 compared to 87 per cent in 2009 and 86 per cent in 2008.

The overall plant availability percentage in 2011 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. Bruce A expects an outage of approximately one week on Unit 3 in July 2011 and, following approval from the Canadian Nuclear Safety Commission, the West Shift Plus outage of approximately six months is scheduled to commence in early November 2011 on Unit 3. The West Shift Plus outage is a key part of the life extension strategy for Unit 3 and is an extension of the West Shift program which was successfully executed in 2009. A maintenance outage of approximately three weeks commenced on February 1, 2011 on Bruce B Unit 8 and outages of approximately seven weeks are scheduled to begin in mid-April 2011 for Bruce B Unit 7 and in mid-October 2011 for Bruce B Unit 5.

Bruce A

Under a contract with the OPA, all of the output from Bruce A is sold at a fixed price per MWh, adjusted annually for inflation on April 1. In addition, fuel costs are recovered from the OPA.

Bruce A Fixed Price

		per MWh
April 1, 2010	March 31, 2011	$64.71
April 1, 2009	March 31, 2010	$64.45
April 1, 2008	March 31, 2009	$63.00

Bruce B

As part of Bruce Power's contract with the OPA, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B Floor Price

		per MWh
April 1, 2010	March 31, 2011	$48.96
April 1, 2009	March 31, 2010	$48.76
April 1, 2008	March 31, 2009	$47.66

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 monthly average 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 2010 realized price of $58 per MWh reflected revenues recognized from both the floor price mechanism and contract sales. Realized prices were $64 per MWh and $57 per MWh in 2009 and 2008, respectively. Most of the higher-priced contracts entered into in prior years expired at December 31, 2010, which is expected to result in a further reduction in realized prices at Bruce B for future periods. As at December 31, 2010, Bruce B had entered into fixed-price contracts to sell forward approximately 500 GWh for 2011 and 700 GWh for 2012, representing TransCanada's proportionate share.

U.S. Power U.S. Power owns approximately 3,800 MW of power generation capacity, consisting of Ravenswood, TC Hydro, Ocean State Power (OSP), and 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 20 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 Kibby Wind is a 132 MW wind farm located in Maine. The first 66 MW phase of Kibby Wind was placed in service in October 2009 and the second 66 MW phase went into service in October 2010.

U.S. Power conducts its business primarily in the deregulated New England, New York and PJM Interconnection power markets, and continues to expand its marketing presence and customer base. PJM Interconnection is a regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia. U.S. Power focuses on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in these markets. To manage exposure to fluctuations in spot prices, power sales are hedged with the purchase of power or the purchase of fuel to generate power from its assets, effectively locking in positive margins.

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 each 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.

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. This capacity market 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 was determined by annual competitive FCM auctions, which are held three years in advance of the applicable capacity year. 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.

U.S. Power Comparable EBIT(1)(2)

Year ended December 31 *(millions of U.S. dollars)*	**2010**	2009	2008
Revenues			
Power(3)	**1,090**	742	1,143
Capacity	**231**	169	80
Other(3)(4)	**78**	79	42
	1,399	990	1,265
Commodity purchases resold(3)			
Power	**(543)**	(309)	(510)
Other(5)			(257)
	(543)	(309)	(767)
Plant operating costs and other(4)	**(521)**	(471)	(242)
General, administrative and support costs	**(32)**	(40)	(38)
Comparable EBITDA(1)	**303**	170	218
Depreciation and amortization	**(116)**	(92)	(38)
Comparable EBIT(1)	**187**	78	180

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

(2) Includes phases one and two of Kibby Wind, and Ravenswood as of October 2009, October 2010 and August 2008, respectively.

(3) Effective January 1, 2010, the net impact of derivatives used to purchase and sell power, natural gas and fuel oil to manage U.S. Power's assets is presented on a net basis in Power Revenues. Comparative results for 2009 and 2008 reflect amounts reclassified to Power Revenues from Commodity Purchases Resold and Other Revenues.

(4) Includes revenues and costs related to a third-party service agreement at Ravenswood.

(5) Includes the cost of excess physical natural gas not used in operations, which was purchased under the terms of contracts that expired in 2008.

U.S. Power Operating Statistics[1]

Year ended December 31	**2010**	2009	2008
Sales Volumes (GWh)			
Supply			
Generation	**6,755**	5,993	3,974
Purchased	**8,899**	5,310	6,020
	15,654	11,303	9,994
Sales			
Contracted	**14,485**	10,205	9,758
Spot	**1,169**	1,098	236
	15,654	11,303	9,994
Plant Availability[2]	**86%**	79%	75%

(1) Includes phases one and two of Kibby Wind, and Ravenswood as of October 2009, October 2010 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 US$303 million in 2010, US$133 million higher than the US$170 million earned in 2009. The increase was primarily due to growth in capacity revenue, higher volumes of power sold in the New England and New York markets, reduced lease costs, higher realized prices and incremental earnings from Kibby Wind.

U.S. Power's Power Revenues of US$1,090 million in 2010 increased US$348 million from US$742 million in 2009 primarily due to higher volumes of power sold, higher realized power prices, and incremental revenues from Kibby Wind. Capacity Revenue of US$231 million in 2010 increased US$62 million from US$169 million in 2009 primarily due to higher capacity prices as a result of 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 increases in capacity prices were partially offset by the impact of the Ravenswood Unit 30 outage, which occurred from September 2008 to May 2009.

Power Commodity Purchases Resold increased US$234 million in 2010 compared to 2009 primarily due to an increase in the quantity of power purchased for resale under U.S. Power's power sales commitments to wholesale, commercial and industrial customers in New England.

Plant Operating Costs and Other increased US$50 million in 2010 compared to 2009 primarily due to higher generation volumes and fuel costs, partially offset by reduced lease costs.

Depreciation and Amortization increased US$24 million in 2010 compared to 2009 and includes a full year of depreciation expense for phase one of Kibby Wind.

U.S. Power's Comparable EBITDA was US$170 million in 2009, US$48 million lower than the US$218 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 the benefit of 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 and by incremental EBITDA from a full year of operations at the Ravenswood facility, which was acquired in August 2008. 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.

U.S. Power achieved plant availability of 86 per cent in 2010 compared to 79 per cent in 2009 and 75 per cent in 2008. The fluctuations in availability were primarily due to the unplanned outage of the Ravenswood Unit 30 from September 2008 to May 2009.

In 2010, seven per cent of power sales volumes were sold into the spot market compared to 10 per cent in 2009. As at December 31, 2010, U.S. Power had entered into fixed-price power sales contracts to sell approximately 11,400 GWh in 2011 and 6,600 GWh in 2012, including financial contracts. Certain contracted volumes are dependent on customer usage levels and actual amounts contracted in future periods will depend on market liquidity and other factors.

Natural Gas Storage TransCanada 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, and 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 TransCanada'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. Alberta-based storage will continue to serve market needs and could play an important role as additional natural gas supplies are connected to North American markets. Energy's natural gas storage business operates independently from TransCanada's regulated natural gas transmission business and from ANR's regulated storage business, which is included in the Natural Gas Pipelines segment.

TransCanada 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 TransCanada's storage facilities provide customers with the ability to capture value from short-term price movements. At December 31, 2010, TransCanada had contracted approximately 56 per cent of the total 129 Bcf of working gas storage capacity in 2011 and 27 per cent of storage capacity in 2012. Earnings from third-party storage capacity contracts are recognized over the terms of the contracts.

Proprietary natural gas storage transactions consist 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, TransCanada locks in future positive margins, effectively eliminating its exposure to natural gas seasonal price spreads. The seasonal nature of natural gas storage generally results in higher revenue in the winter months.

Natural Gas Storage's Comparable EBITDA in 2010 was $132 million compared to $164 million in 2009. The $32 million decrease in EBITDA was primarily due to decreased proprietary natural gas and third-party storage revenues as a result of lower realized natural gas price spreads. Natural Gas Storage's Comparable EBITDA was $164 million in

2009 compared to $138 million in 2008. The increase in 2009 was due to increased storage revenues as a result of higher realized natural gas price spreads.

Business Development Business Development Comparable EBITDA losses decreased $5 million in 2010 compared to 2009 and $15 million in 2009 compared to 2008 primarily due to the timing of expenses on certain key projects.

ENERGY OPPORTUNITIES AND DEVELOPMENTS

Bruce Power In accordance with terms of the 2005 Bruce Power Refurbishment Implementation Agreement (BPRIA) between Bruce Power and the OPA, Bruce A committed to refurbish and restart the idle Units 1 and 2 and refurbish the operating Units 3 and 4 under certain conditions.

In August 2007, Bruce Power and the OPA agreed to amend the BPRIA to expand the scope of the refurbishment contemplated for Unit 4.

In July 2009, Bruce Power and the OPA agreed to amend the BPRIA to include the following:

- elimination of the requirement that annual net payments received under the Bruce B floor price mechanism be subject to repayment in future years. Instead, amounts received under the floor price mechanism within a calendar year will be subject to repayment only if the monthly average spot price for that year exceeds the floor price;

- Bruce Power will receive deemed generation payments from the OPA at contract prices in the event Bruce Power's generation is reduced due to system curtailments on the IESO-controlled grid in Ontario;

- the original terms of the BPRIA provided that the cumulative contingent support payments received by Bruce A, which are equal to the difference between the fixed prices under the BPRIA and spot market prices, were capped at $575 million until both of Units 1 and 2 go into commercial service. The amendment removed the $575 million cap on these contingent support payments and stipulated that the payments would be suspended if both Units 1 and 2 were not in commercial service by December 31, 2011; and

- 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 costs for Units 1 and 2 in excess of $3.4 billion. Previously, the OPA was responsible for 25 per cent of cost refurbishment above $3.4 billion through a future adjustment to the fixed price paid to Bruce Power for power generated by the Bruce A units.

In February 2011, the BPRIA was further amended to reflect the following:

- the suspension date for contingent support payments on Bruce A output was extended to June 1, 2012 from December 31, 2011 and, as a result, all output from Bruce A will receive spot prices from June 1, 2012 until the restart of Units 1 and 2 is complete; and

- a recovery of costs incurred by Bruce A in connection with development of fuel programs.

Refurbishment work on Units 1 and 2 reached a significant milestone in December 2010 with Atomic Energy of Canada Ltd.'s (AECL) substantial completion of work in connection with Unit 2. Substantial completion of the Unit 2 work resulted in a significant reduction of the AECL workforce and enabled AECL to focus on the installation of FCAs at Unit 1. The installation of these FCAs is the final stage of AECL's work on the reactors. AECL is expected to complete FCA installation on Unit 1 in second quarter 2011.

Subject to regulatory approval, Bruce Power expects to load fuel into Unit 2 in second quarter 2011 and achieve a first synchronization of the generator to the electrical grid by the end of 2011, with commercial operation expected to occur in first quarter 2012. Bruce Power expects to load fuel into Unit 1 in third quarter 2011, with a first synchronization of the generator during first quarter 2012 and commercial operation expected to occur during third quarter 2012. Plant commissioning and testing are underway and will accelerate in second quarter 2011 when construction activities are essentially complete. TransCanada's share of the total capital cost is expected to be approximately $2.4 billion.

As at December 31, 2010, Bruce A had incurred approximately $4.0 billion in costs for the refurbishment and restart of Units 1 and 2, and approximately $0.3 billion for the refurbishment of Units 3 and 4.

Halton Hills The $700 million Halton Hills generating station went into service on September 1, 2010, on time and on budget. Power from the 683 MW natural gas-fired power plant in Halton Hills, Ontario is sold to the OPA under a 20-year Clean Energy Supply contract.

Oakville In September 2009, the OPA awarded TransCanada a 20-year Clean Energy Supply contract to build, own and operate a 900 MW power generating station in Oakville, Ontario. TransCanada expected to invest approximately $1.2 billion in the natural gas-fired, combined-cycle plant. In October 2010, the Government of Ontario announced that it would not proceed with the Oakville generating station. TransCanada is negotiating a settlement with the OPA that would terminate the Clean Energy Supply contract and compensate TransCanada for the economic consequences associated with the contract's termination.

Kibby Wind The 66 MW second phase of the Kibby Wind power project went into service in October 2010 and included the installation of an additional 22 turbines, which were all erected ahead of schedule and on budget. The two phases of the project have a combined capacity of 132 MW and total capital cost of US$350 million. A total of 30 MW of energy and associated renewable energy credits produced by Kibby Wind have been sold at fixed prices for a term of 10 years. Phase one of the project received government incentive payments totalling US$44 million under the federal U.S. stimulus package. Phase two is also expected to qualify for payments under the program.

Sundance A On February 8, 2011, TransCanada received from TransAlta Corporation (TransAlta) notice under the Sundance A PPA that TransAlta has determined that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored and that TransAlta therefore seeks to terminate the PPA in respect of those units. TransCanada has not received any information that would validate TransAlta's determination that the units cannot be economically restored to service.

TransCanada has 10 business days from the date of TransAlta's notice to either agree with or dispute TransAlta's determination that the Sundance 1 and 2 generating units cannot be economically repaired, replaced, rebuilt or restored. TransCanada will assess any information provided by TransAlta during this 10-day period. If TransCanada disputes TransAlta's determination, the issue will be resolved using the dispute resolution procedure under the terms of the PPA.

In December 2010, the Sundance 1 and 2 generating units were withdrawn from service for testing. In January 2011, these same units were subject to a force majeure claim by TransAlta under the PPA. TransCanada has received insufficient information to make an assessment of TransAlta's force majeure claim and therefore has recorded revenues under the PPA as though this event was a normal plant outage.

Sundance B In second quarter 2010, Sundance B Unit 3 experienced an unplanned outage related to mechanical failure of certain generator components that the facility operator, TransAlta, has asserted is a force majeure event. TransCanada has received no information that validates a claim of force majeure and therefore has recorded revenues under the PPA as though this event was a normal plant outage. TransCanada is pursuing the remedies available to it under the terms of the PPA.

Coolidge At December 31, 2010, construction of the US$500 million Coolidge generating station located near Phoenix, Arizona was approximately 95 per cent complete and commissioning was approximately 80 per cent finished. 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.

Cartier Wind Construction activity on the 212 MW Gros-Morne and 58 MW Montagne-Sèche wind farms continued throughout 2010. The Montagne-Sèche project and the 101 MW first phase of the Gros-Morne project are expected to be operational by the end of 2011. The 111 MW second phase of the Gros-Morne project is expected to be operational by the end of 2012. Gros-Morne and Montagne-Sèche are the fourth and fifth wind farms of the Cartier Wind project in Québec. Once they are complete, Cartier Wind, which is 62 per cent owned by TransCanada, 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.

Bécancour In June 2010, Hydro-Québec notified TransCanada it would exercise its option to extend the agreement suspending all electricity generation from the Bécancour power plant through 2011. Under the original agreement signed in June 2009, 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. TransCanada will continue to receive payments under the agreement similar to those that would have been received under the normal course of operation.

Ravenswood Subsequent to closing the acquisition of Ravenswood, TransCanada experienced a forced outage event related to Ravenswood's 972 MW Unit 30. The unit returned to service in May 2009. Insurers of the business interruption and physical damage claim have denied coverage. TransCanada has filed a claim against the insurers to enforce its rights under the insurance policies. Settlement discussions have not resolved the dispute over coverage and litigation proceedings are ongoing.

Power Transmission Line Projects In May 2010, TransCanada concluded a successful open season for the proposed Zephyr power transmission (Zephyr) project, during which it received signed agreements for the full 3,000 MW of wind-generated capacity with renewable energy developers in Wyoming. Support from key markets and a positive regulatory environment are necessary before the significant siting and permitting activities required to construct the project will commence. TransCanada anticipates making a decision in 2011 on whether to proceed with the project. The Zephyr project is a 1,609 km (1,000 miles), 500 kilovolt, high voltage direct current line (HVDC) expected to cost approximately US$3 billion. TransCanada expects commercial operations would commence in late 2016 or early 2017 if the project proceeds.

TransCanada closed the open season for the Chinook power transmission project in December 2010 without allocating capacity to Montana shippers. TransCanada is still developing the project and will continue discussions with Montana wind developers and other market participants to identify their future transmission requirements. The Chinook transmission project is a 1,609 km (1,000 miles), 500 kilovolt, HVDC transmission line expected to cost approximately US$3 billion.

ENERGY BUSINESS RISKS

Fluctuating Power and Natural Gas Market Prices TransCanada operates in competitive power and natural gas markets in North America. Power and natural gas price volatility is caused by fluctuating supply and demand, and by general economic conditions. Sales of uncontracted power volumes into the spot market can be subject to price volatility, directly affecting earnings. To mitigate this risk, Energy commits a significant portion of its supply to sales contracts that are medium-term to long-term while retaining an amount of unsold supply in case of unexpected plant outages and in order to provide operational flexibility in managing the Company's portfolio of wholly owned assets. This unsold supply is subsequently sold under shorter-term forward arrangements or into the spot market and is exposed to fluctuating power and natural gas market prices. Additionally, as power sales contracts expire, new forward contracts are entered into at the prevailing market prices.

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 for all of its output. However, Bruce B's results during this period remain subject to the impact of fluctuating spot prices upon the settlement of fixed-price contract sales. The majority of contracted sales at Bruce B expired at December 31, 2010. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA and 100 per cent of Eastern Power sales volumes are sold under long-term contracts. As discussed, all Bruce A output after July 1, 2012 will be subject to spot market pricing if both Units 1 and 2 are not operating, which will continue until such time as both units are operational.

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 capacity sales contracts and proprietary natural gas purchases and sales.

Capacity Payments The parameters that drive U.S. Power capacity prices are reset periodically and are affected by a number of factors including the cost of entering the market, reflected in administratively-set demand curves, available supply and fluctuations in forecast demand. With the downturn in the economy, there has been a decrease in demand that, combined with increased supply, has put downward pressure on capacity prices. On January 28, 2011, the FERC issued a decision in a rate filing made by the NYISO relating to the periodic reset of the demand curves. The FERC made several determinations related to such demand curves and ordered the NYISO to make revisions in a compliance filing no later than March 29, 2011. The FERC decision will likely result in higher demand curves that may positively affect capacity prices, but until the compliance filing and additional orders are issued and finalized, it is unclear what the impact on capacity prices will be.

Plant Availability Optimizing and maintaining plant availability is essential to the continued success of the Energy business. High levels of performance are achieved through the use of risk-based comprehensive preventative maintenance programs, prudent operating and capital investment, and a skilled workforce. Further mitigation is provided through the contractual obligations to TransCanada of its power suppliers under the Sundance and Sheerness PPAs, including the payment of market-based penalties related to availability requirements and by certain sales contracts that share operating risks with the purchaser. In the event a PPA power supplier experiences a verified force majeure event, TransCanada is not entitled to receive market-based penalties for the duration of the verified force majeure event and the monthly capacity payments paid to the supplier are eliminated during the same period. Unexpected plant outages, including unexpected delays in ending 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 TransCanada 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 TransCanada'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 construction programs in Québec, Arizona and Ontario, including its investment in Bruce Power, are subject to execution, capital cost and permitting risks.

Regulation of Power Markets TransCanada 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 TransCanada as a generator and marketer of electricity. These may be in the form of market rule changes, price caps, emission controls, unfair cost allocations to generators and attempts by others to take out-of-market actions to build excess generation, all of which negatively affect the price of capacity or energy, or both. In addition, TransCanada's development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. TransCanada continues to monitor regulatory issues and regulatory reform and participate in and lead related discussions.

Refer to the Risk Management and Financial Instruments section in this MD&A for information on additional risks and managing risks in the Energy business.

ENERGY OUTLOOK

TransCanada expects that results from its Energy operations in 2011 will be materially consistent with those in 2010. There will be a positive earnings impact from a full year of earnings from Halton Hills and Kibby Wind, and a partial year of earnings from Coolidge, which is expected to be commissioned in second quarter 2011. Output from these plants, as well as a significant portion of output from Energy's other assets, has been sold under long-term contracts and provides a stable earnings base for the Energy business.

The Company expects the positive impact on earnings from the new assets coming into service will be tempered by results from Energy facilities whose output is sold under shorter-term forward arrangements or at spot prices. These facilities are expected to be affected to a greater degree by the current economic climate, which continues to have a negative impact on demand, liquidity and commodity and capacity prices.

Other factors such as plant availability, regulatory changes, weather, currency movements and overall stability of the energy industry can also affect 2011 EBIT. Refer to the Energy Business Risks section in this MD&A for a complete discussion of these and other factors affecting the Energy Outlook.

Capital Expenditures Energy's total capital expenditures in 2010 were $1.1 billion. Energy's overall capital spending in 2011 is expected to be approximately $1 billion, including cash calls for the Bruce A refurbishment and restart project, and continued construction at Coolidge and Cartier Wind.

CORPORATE

Corporate had a Comparable EBIT loss of $99 million in 2010 compared to losses of $117 million and $104 million in 2009 and 2008, respectively. The decrease in the loss in 2010 was primarily due to lower support services and other corporate costs. The increase in the loss in 2009 compared to 2008 was 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)*	**2010**	2009	2008
Interest on long-term debt[1]			
Canadian dollar-denominated	**514**	548	523
U.S. dollar-denominated	**680**	645	479
Foreign exchange	**20**	92	36
	1,214	1,285	1,038
Other interest and amortizations	**74**	27	46
Capitalized interest	**(587)**	(358)	(141)
	701	954	943

(1) Includes interest on Junior Subordinated Notes.

Interest Expense in 2010 decreased $253 million to $701 million from $954 million in 2009. Interest on Canadian dollar-denominated debt decreased in 2010 compared to 2009 primarily due to debt maturities. Interest on U.S. dollar-denominated debt increased in 2010 compared to 2009 due to new debt issues of US$1.0 billion in September 2010, US$1.25 billion in June 2010 and US$2.0 billion in January 2009, partially offset by the impact of a weaker U.S. dollar. Other Interest and Amortization expense in 2010 was negatively affected by additional financing charges on committed credit facilities and increased losses from changes in the fair value of derivatives used to manage TransCanada's exposure to fluctuating interest rates, although the majority of these derivatives were settled prior to December 31, 2010. Interest Expense was positively impacted by higher capitalization of interest in 2010 relating to the Company's larger capital spending program primarily for the construction of Keystone and refurbishment and restart of Bruce A.

Interest Expense in 2009 increased $11 million to $954 million from $943 million in 2008. The increase in 2009 compared to 2008 reflected new Canadian debt issues of $700 million in February 2009 and $500 million in August 2008. Interest on U.S. dollar-denominated debt increased in 2009 compared to 2008 due to new debt issues of

US$2.0 billion in January 2009 and US$1.5 billion in August 2008. In addition, Interest Expense increased in 2009 compared to 2008 due to the impact of a stronger U.S. dollar on U.S. dollar-denominated interest. Increases in Interest Expense were significantly offset by higher capitalization of interest in 2009 relating to the Company's larger capital spending program primarily for the construction of Keystone, the acquisition of the remaining ownership interest in Keystone from ConocoPhillips, and refurbishment and restart of Bruce A.

Interest Income and Other was $94 million in 2010 compared to $121 million and $54 million in 2009 and 2008, respectively. The year-over-year changes primarily reflected the positive impact of a weakening U.S. dollar on the translation of U.S. dollar working capital balances throughout each year. The increase in 2009 compared to 2008 was also due to higher gains from derivatives used to manage the Company's exposure to foreign exchange rate fluctuation.

Income Taxes were $380 million, $387 million and $602 million in 2010, 2009, and 2008, respectively. The decrease of $7 million in 2010 compared to 2009 was primarily due to reduced pre-tax earnings, partially offset by positive income tax adjustments that reduced income taxes in 2009, including $30 million of favourable adjustments arising from a reduction in the Province of Ontario's corporate income tax rates. In 2010, the Company recorded a benefit in Current Income Taxes with an offsetting provision in Future Income Taxes as a result of bonus depreciation for U.S. income tax purposes on Keystone assets placed in service June 30, 2010. 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 differentials and the positive income tax adjustments in 2009.

Non-Controlling Interests were $115 million in 2010 compared to $96 million and $130 million in 2009 and 2008, respectively. The $19 million increase in 2010 compared to 2009 was primarily due to increased PipeLines LP earnings as a result of higher revenues for Northern Border and the acquisition in 2009 of North Baja, partially offset by the impact of a weaker U.S. dollar in 2010. The decrease in 2009 compared to 2008 was primarily due to the non-controlling interests' portion of Portland's Calpine bankruptcy distributions in 2008, partially offset by higher PipeLines LP earnings and the impact of a stronger U.S. dollar in 2009.

LIQUIDITY AND CAPITAL RESOURCES

TransCanada'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 provide for planned growth. TransCanada's liquidity position remains solid, underpinned by predictable cash flow from operations, cash balances on hand from preferred share and debt issues, and unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$800 million, maturing in November 2011, December 2012 and December 2012, respectively. These facilities also support the Company's commercial paper programs. In addition, at December 31, 2010, TransCanada's proportionate share of unutilized capacity on committed bank facilities at TransCanada-operated affiliates was $111 million with maturity dates in 2011 and 2012. As at December 31, 2010, TransCanada had remaining capacity of $1.75 billion, $2.0 billion and US$1.75 billion under its equity, Canadian debt and U.S. debt shelf prospectuses, respectively. In lieu of making cash dividend payments, a portion of declared dividends for common and preferred shares are expected to be paid in common shares issued under the Company's DRP. TransCanada's liquidity, market and other risks are discussed further in the Risk Management and Financial Instruments section in this MD&A.

SUMMARIZED CASH FLOW

Year ended December 31 *(millions of dollars)*	**2010**	2009	2008
Funds generated from operations[1]	**3,331**	3,080	3,021
(Increase)/decrease in operating working capital	**(249)**	(90)	135
Net Cash Provided by Operations	**3,082**	2,990	3,156

(1) Refer to the Non-GAAP Measures section in this MD&A for further discussion of Funds Generated from Operations.

HIGHLIGHTS

Investing Activities

Capital expenditures and acquisitions, including assumed debt, totalled approximately $18 billion over the three-year period ending December 31, 2010.

Dividends

TransCanada's Board of Directors declared a $0.42 per common share dividend for the quarter ending March 31, 2011, an increase of five per cent over the previous dividend amount. The Board of Directors also declared regular quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011 and $0.275 per Series 5 preferred share for the three-month period ending April 30, 2011.

CASH FLOW AND CAPITAL RESOURCES

Cash Generated from Operations

Net Cash Provided by Operations was $3.1 billion in 2010 compared to $3.0 billion and $3.2 billion in 2009 and 2008, respectively. Net Cash Provided by Operations reflects Funds Generated from Operations, net of changes in operating working capital.

Funds Generated from Operations

Funds Generated from Operations were $3.3 billion in 2010 compared to $3.1 billion and $3.0 billion in 2009 and 2008, respectively. The increase in 2010 compared to 2009 was primarily due to an income tax benefit generated from bonus depreciation for U.S. tax purposes on Keystone assets placed in service on June 30, 2010 and increased cash from earnings. The increase in 2009 compared to 2008 was primarily due to increased cash from earnings, partially offset by higher pension contributions in 2009 and the $152 million after-tax Calpine bankruptcy distributions in 2008.

As at December 31, 2010, TransCanada's current liabilities were $5.7 billion and current assets were $3.2 billion resulting in a working capital deficiency of $2.5 billion. Excluding $2.1 billion of Notes Payable under the Company's commercial paper programs and draws on its line-of-credit facilities, TransCanada's working capital deficiency was $0.4 billion. The Company believes this shortfall can be managed through its ability to generate cash flow from operations as well as its ongoing access to capital markets.

Investing Activities

Capital expenditures totalled $5.0 billion in 2010 compared to $5.4 billion in 2009 and $3.1 billion in 2008. Expenditures in 2010, 2009 and 2008 related primarily to the construction of Keystone, the refurbishment and restart at Bruce A, construction of other new pipeline and power facilities, and the expansion and maintenance of existing pipelines.

In August 2009, the Company purchased ConocoPhillips' remaining interest of approximately 20 per cent in Keystone for US$553 million plus the assumption of US$197 million of short-term debt. In the first seven months of 2009, TransCanada solely 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 solely funded $362 million of cash calls, resulting in an incremental increase in ownership of approximately 12 per cent for $176 million. TransCanada's ownership interest in Keystone was approximately 62 per cent at December 31, 2008.

TransCanada acquired Ravenswood from National Grid plc in August 2008 for US$2.9 billion.

Financing Activities

In 2010, TransCanada issued $2.4 billion of long-term debt and its proportionate share of long-term debt issued by joint ventures was $177 million. Also in 2010, the Company reduced its long-term debt by $494 million and its proportionate share of the long-term debt of joint ventures by $254 million, and increased notes payable by $474 million. This financing activity included the items noted below.

At December 31, 2010, total committed revolving and demand credit facilities of $5.1 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 TransCanada PipeLines Limited (TCPL) credit facility, maturing December 2012. The facility was fully available at December 31, 2010;

- a US$300 million committed, syndicated, revolving credit facility, maturing February 2013. This facility is part of a US$1.0 billion TransCanada PipeLine USA Ltd. (TCPL USA) credit facility established in 2007 to partially finance the ANR acquisition and increased ownership in Great Lakes. At December 31, 2010, this facility was fully drawn;

- a US$1.0 billion committed, syndicated, revolving, extendible TransCanada Keystone Pipeline, L.P. credit facility, maturing November 2011 with a one-year extension at the option of the borrower. The facility was fully available at December 31, 2010 and supports a commercial paper program dedicated to funding a portion of capital expenditures for Keystone;

- a US$1.0 billion committed, syndicated, revolving TCPL USA credit facility, maturing December 2012, with a one-year extension at the option of the borrower. At December 31, 2010, US$200 million was drawn on this facility; and

- demand lines totalling $800 million, which support the issuance of letters of credit and provide additional liquidity. At December 31, 2010, the Company had used approximately $382 million of these demand lines for letters of credit.

In July 2009, TransCanada sold North Baja to PipeLines LP and received aggregate consideration totalling approximately US$395 million, including US$200 million in cash and 6,371,680 common units of PipeLines LP. The transaction resulted in TransCanada's ownership in PipeLines LP increasing to 42.6 per cent. Subsequent to the transaction, TransCanada'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.

The Company is well positioned to fund its existing capital program through its internally-generated cash flow, its DRP and its continued access to capital markets. TransCanada will also continue to examine opportunities for portfolio management, including a role for PipeLines LP, in financing its capital program.

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.

2011 and 2010 Long-Term Debt Financing Activities

In September 2010, TCPL issued US$1.0 billion of Senior Notes maturing October 1, 2020 and bearing interest at 3.80 per cent. The notes were issued under a US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

In June 2010, TCPL issued US$500 million and US$750 million of Senior Notes maturing on June 1, 2015 and June 1, 2040, respectively, and bearing interest at 3.40 per cent and 6.10 per cent, respectively. These notes were issued under the US$4.0 billion debt shelf prospectus filed in December 2009. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

In January 2011, TCPL retired $300 million of 4.30 per cent Medium-Term Notes.

In February 2010, the Company retired US$120 million of 6.125 per cent Medium-Term Notes and in August 2010, the Company retired $130 million of 10.50 per cent debentures.

In September 2010, TQM retired $100 million of 7.53 per cent Series I bonds and $75 million of 3.906 per cent Series J bonds. In July 2010, TQM issued $100 million of bonds maturing in September 2017 and bearing interest at 4.25 per cent.

In April 2010, Iroquois retired US$200 million of Series I bonds bearing interest at 9.16 per cent and issued US$150 million of bonds maturing in April 2020 and bearing interest at 4.96 per cent.

2009 Long-Term Debt Financing Activities

In December 2009, TCPL filed a debt shelf prospectus qualifying the future issuance of up to US$4.0 billion of debt securities in the U.S. The prospectus replaced a US$3.0 billion debt base shelf prospectus filed in January 2009, which had remaining capacity of US$1.0 billion. At December 31, 2010, the December 2009 shelf prospectus had remaining capacity of US$1.75 billion.

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 $300 million and $400 million of Medium-Term Notes 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 pricing supplements under a $1.5 billion Canadian debt base shelf prospectus filed in March 2007.

In January 2009, TCPL issued US$750 million and US$1.25 billion of Senior Unsecured Notes 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 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 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, and in January 2009, the Company retired US$227 million of 6.49 per cent Medium-Term Notes.

In September 2009, TQM issued $75 million of bonds maturing in September 2014 and bearing interest at 4.05 per cent. In August 2009, TQM retired $100 million of 6.50 per cent Series H bonds.

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 September 2009, Northern Border retired US$200 million of 7.75 per cent Senior Notes.

In May 2009, Iroquois issued US$140 million of Senior Unsecured Notes maturing in May 2019 and bearing interest at 6.63 per cent.

2008 Long-Term Debt Financing Activities

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 a $1.5 billion 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. The proceeds from the notes were used to partially fund the Ravenswood acquisition and for general corporate purposes. The 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.

2010 Equity Financing Activities

In June 2010, TransCanada completed a public offering of 14 million Series 5 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus, discussed below. The preferred shares were issued at a price of $25.00 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 5 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.10 per share, payable quarterly, yielding 4.4 per cent per annum for the initial five and a half year period ending January 30, 2016. The dividend rate will reset on January 30, 2016 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.54 per cent. The Series 5 preferred shares are redeemable by TransCanada on January 30, 2016 and on January 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 5 preferred shareholders have the right to convert their shares into Series 6 cumulative redeemable first preferred shares on January 30, 2016 and on January 30 of every fifth year thereafter. The holders of Series 6 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.54 per cent.

In March 2010, TransCanada completed a public offering of 14 million Series 3 cumulative redeemable first preferred shares, including the full exercise of an underwriters' option of two million shares, under its September 2009 base shelf prospectus, discussed below. The preferred shares were issued at a price of $25.00 per share, resulting in gross proceeds of $350 million including the underwriters' option. The holders of the Series 3 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly, yielding 4.0 per cent per annum for the initial five-year period ending June 30, 2015. The dividend rate will reset on June 30, 2015 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 1.28 per cent. The Series 3 preferred shares are redeemable by TransCanada on June 30, 2015 and on June 30 of every fifth year thereafter at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of this offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 3 preferred shareholders have the right to convert their shares into Series 4 cumulative redeemable first preferred shares on June 30, 2015 and on June 30 of every fifth year thereafter. The holders of Series 4 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.28 per cent.

2009 Equity Financing Activities

In September 2009, TransCanada completed a public offering of 22 million Series 1 cumulative redeemable first preferred shares under a prospectus supplement to its September 2009 base shelf prospectus, discussed below, for gross proceeds of $550 million. The holders of the Series 1 preferred shares are entitled to receive fixed cumulative dividends at an annual rate of $1.15 per share, payable quarterly, yielding 4.6 per cent per annum for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield plus 1.92 per cent. The preferred shares are redeemable by TransCanada on or after December 31, 2014 at a price of $25.00 per share plus all accrued and unpaid dividends. The preferred shareholders are eligible to participate in the Company's DRP. The net proceeds of the offering were used to partially fund capital projects, for general corporate purposes and to repay short-term debt.

The Series 1 preferred shareholders have the right to convert their shares into Series 2 cumulative redeemable first preferred shares on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at a yield per annum equal to the sum of the then 90-day Government of Canada treasury bill rate and 1.92 per cent.

In September 2009, TransCanada filed a base shelf prospectus qualifying the future issuance of up to $3.0 billion of common shares, first or second preferred shares, or subscription receipts in Canada and the U.S. until October 2011. This base shelf prospectus replaced the base shelf prospectus filed in July 2008, which was depleted by the common share issuance in June 2009. The Company had $1.75 billion available under the September 2009 prospectus at December 31, 2010.

In June 2009, TransCanada completed a public offering of 58.4 million common shares at a purchase price of $31.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.8 billion. The proceeds were used by TransCanada to partially fund capital projects, including the acquisition of the remaining interest in Keystone, for general corporate purposes and to repay short-term debt.

In November 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. TransCanada contributed an additional US$4 million to maintain its general partnership interest but did not purchase any units. Upon completion of this offering, TransCanada's ownership interest in PipeLines LP was 38.2 per cent.

2008 Equity Financing Activities

In fourth quarter 2008, TransCanada completed a public offering of 35.1 million common shares at a purchase price of $33.00 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.2 billion. The proceeds of the offering were used by TransCanada to partially fund its capital projects, including Keystone, for general corporate purposes and to repay short-term debt. The common shares were issued under a prospectus supplement to the base shelf prospectus filed in July 2008.

In July 2008, TransCanada filed a base shelf prospectus in Canada and the U.S. qualifying the future issuance of up to $3.0 billion of common shares, preferred shares or subscription receipts in Canada and the U.S. until August 2010. The base shelf prospectus replaced a base shelf prospectus filed in January 2007.

In May 2008, TransCanada completed a public offering of 34.7 million common shares at a purchase price of $36.50 per share. The issue, including the full exercise of a 15 per cent over-allotment option by the underwriters, resulted in gross proceeds of $1.3 billion. These proceeds were used to partially fund the Ravenswood acquisition and the Company's capital projects, and for general corporate purposes. The common shares were issued under a prospectus supplement to the base shelf prospectus filed in January 2007.

Dividend Reinvestment and Share Purchase Plan

TransCanada's Board of Directors has authorized the issuance of common shares from treasury at a discount to participants in the Company's DRP. Under this plan, eligible holders of common or preferred shares of TransCanada and preferred shares of TCPL 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 three per cent in 2009 and 2010, and was reduced to two per cent commencing with the dividends declared in February 2011. The discount was set at two per cent for 2008 and was increased to three per cent commencing with the dividend declared in February 2009. The Company reserves the right to alter the discount or to satisfy its DRP obligations by instead purchasing shares on the open market at any time. In 2010, dividends of $378 million were paid (2009 $254 million; 2008 $218 million) through the issuance of 11 million (2009 8 million; 2008 6 million) common shares from treasury in accordance with the DRP.

Dividends

Cash dividends on common shares amounting to $710 million were paid in 2010 (2009 $722 million; 2008 $577 million). In addition, cash dividends of $44 million were paid on preferred shares in 2010 (2009 $6 million). The decrease in common share dividends paid in 2010 was primarily due to increased participation in the DRP in lieu of cash dividends, which grew to $378 million in 2010 from $254 million in 2009, partially offset by a greater number of shares outstanding and an increase in the dividend per share amount in 2010. The increase in common share dividends paid in 2009 from 2008 was primarily due to a greater number of shares outstanding and an increase in the dividend per share amount in 2009, partially offset by the Company's issuance in 2009 of $254 million (2008 $218 million) of common shares from treasury under the DRP in lieu of cash dividends. The increase in preferred share dividends paid in 2010 from 2009 was primarily due to a full year of preferred share dividend payments in 2010 on preferred shares issued in September 2009 and the preferred share issuances in 2010.

In February 2011, TransCanada's Board of Directors approved an increase in the quarterly common share dividend payment to $0.42 per share from $0.40 per share for the quarter ending March 31, 2011. This was the eleventh consecutive year in which the dividend was increased, resulting in a per share dividend that has more than doubled since 2000. In addition, the Board of Directors declared quarterly dividends of $0.2875 and $0.25 per Series 1 and 3 preferred share, respectively, for the quarter ending March 31, 2011 and $0.275 per Series 5 preferred share for the three-month period ended April 30, 2011.

CONTRACTUAL OBLIGATIONS

Obligations and Commitments

At December 31, 2010, the Company had $17.9 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes, compared to $16.7 billion of total long-term debt and $1.0 billion of Junior Subordinated Notes at December 31, 2009. TransCanada's share of the total long-term debt of joint ventures, including capital lease obligations, was $0.9 billion at December 31, 2010, compared to $1.0 billion at December 31, 2009. Total Notes Payable, including TransCanada's proportionate share of the notes payable of joint ventures, were $2.1 billion at December 31, 2010 and $1.7 billion at December 31, 2009. TransCanada 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

		Payments Due by Period			
Year ended December 31 *(millions of dollars)*	Total	Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt[1]	19,566	943	2,122	2,085	14,416
Capital lease obligations	207	16	38	48	105
Operating leases[2]	784	74	150	142	418
Purchase obligations	9,599	2,393	2,102	1,527	3,577
Other long-term liabilities reflected on the balance sheet	976	16	32	37	891
	31,132	3,442	4,444	3,839	19,407

(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 10 years.

TransCanada'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. TransCanada's share of power purchased under the PPAs in 2010 was $363 million (2009 $384 million; 2008 $398 million).

At December 31, 2010, 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)*	Total	Payments Due by Period Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	17,922	894	2,012	2,034	12,982
Junior subordinated notes	985				985
Long-term debt of joint ventures	659	49	110	51	449
	19,566	943	2,122	2,085	14,416

INTEREST PAYMENTS

Year ended December 31 *(millions of dollars)*	Total	Payments Due by Period Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Long-term debt	16,721	1,140	2,190	1,973	11,418
Junior subordinated notes[1]	410	63	126	126	95
Long-term debt of joint ventures	381	48	90	80	163
	17,512	1,251	2,406	2,179	11,676

(1) Payments were calculated assuming the notes would be redeemed after 10 years.

At December 31, 2010, the Company's approximate future purchase obligations were as follows:

PURCHASE OBLIGATIONS[1]

Year ended December 31 (millions of dollars)	Total	Payments Due by Period Less than one year	1 - 3 years	3 - 5 years	More than 5 years
Natural Gas Pipelines					
Transportation by others[2]	651	189	197	111	154
Capital expenditures[3][4]	239	174	65		
Other	2	1	1		
Oil Pipelines					
Capital expenditures[3][5]	1,172	783	389		
Other	49	4	8	8	29
Energy					
Commodity purchases[6]	5,467	547	1,158	1,201	2,561
Capital expenditures[3][7]	567	541	26		
Other[8]	1,420	133	251	204	832
Corporate					
Information technology and other	32	21	7	3	1
	9,599	2,393	2,102	1,527	3,577

(1) The amounts in this table exclude funding contributions to pension plans.

(2) Rates are based primarily 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, the issuance of senior debt and subordinated capital, and through portfolio management.

(4) Capital expenditures primarily relate to the construction costs of the Alberta System expansion, Guadalajara and other natural gas pipeline projects.

(5) Capital expenditures relate to the Keystone U.S. Gulf Coast Expansion.

(6) 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.

(7) Capital expenditures primarily relate to TransCanada's share of the construction and development costs of Bruce Power and Cartier Wind.

(8) 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.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business. Potential future commitments are discussed in the Opportunities and Developments sections for Natural Gas Pipelines, Oil Pipelines and Energy in this MD&A.

In 2011, TransCanada expects to make funding contributions of approximately $98 million to its defined benefit pension plans and approximately $28 million to the Company's other post-retirement benefit plans, savings plan and defined contribution pension plans. This is consistent with total funding contributions of $127 million in 2010. TransCanada's proportionate share of funding contributions expected to be made by joint ventures to their respective pension and other post-retirement benefit plans in 2011 is approximately $87 million and $7 million, respectively, compared to total contributions of $58 million in 2010.

The next actuarial valuation for the Company's pension and other post-retirement benefit plans will be carried out as at January 1, 2012. Based on current market conditions, TransCanada expects funding requirements for these plans to continue at the anticipated 2011 level for the next several years to amortize solvency deficiencies in addition to normal costs. The Company's 2011 net benefit cost is expected to increase from 2010 primarily due to a lower projected discount rate. 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. TransCanada's share of these signed commitments is $205 million. The Company expects $193 million and $12 million to be paid in 2011 and 2012, respectively.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. At December 31, 2010, the Company accrued approximately $59 million (2009 $67 million) related to operating facilities, which represents the estimated amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada 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

TransCanada and its joint venture partners on Bruce Power, 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, TransCanada and BPC have each 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. TransCanada's share of the potential exposure under these Bruce A and Bruce B guarantees was estimated to be $739 million at December 31, 2010. The fair value of these Bruce Power guarantees is estimated to be $42 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. TransCanada's share of the potential exposure under these guarantees was estimated at December 31, 2010 to range from $227 million to a maximum of $539 million. The fair value of these guarantees is estimated to be $9 million, which has been included in Deferred Amounts. For certain of these entities, any payments made by TransCanada 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

TransCanada has exposure to market risk, counterparty credit risk and liquidity risk. TransCanada engages in risk management activities with the objective of protecting earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure TransCanada'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 financial risk management framework. Internal audit personnel assist the Audit Committee in its oversight role by performing regular and ad-hoc reviews of financial 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. TransCanada 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.

Where possible, derivative financial instruments are designated as hedges, but in some cases derivatives do not meet the specific criteria for hedge accounting treatment and are accounted for at fair value with changes in fair value recorded in Net Income in the period of change. This may expose the Company to increased variability in reported operating results because the fair value of the derivative instruments can fluctuate significantly from period to period. However, the Company enters into the arrangements as they are considered to be effective economic hedges.

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 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 sale price of electricity on the cost of natural gas, effectively locking in a margin. A significant portion of the electricity needed to fulfil 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 fair value accounting is not required, 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 and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain exemptions.

Natural Gas Storage Commodity Price Risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated 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. TransCanada 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 on these forward contracts are not representative of the amounts that will be realized on settlement.

At December 31, 2010, the fair value of proprietary natural gas inventory in storage, measured using a weighted average of forward prices for the following four months less selling costs, was $49 million (2009 $73 million). The change in fair value of proprietary natural gas inventory in storage in 2010 resulted in pre-tax unrealized losses of $16 million (2009 gains of $3 million; 2008 losses of $7 million), which were recorded as a decrease to Revenues and to Inventories. The change in fair value of natural gas forward purchase and sales contracts in 2010 resulted in pre-tax unrealized gains of $6 million (2009 losses of $2 million; 2008 gains of $7 million), which were recorded as an increase to Revenues and to Inventories.

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.

TransCanada's earnings from its Natural Gas Pipelines and Energy segments are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada's earnings. This foreign exchange impact is partially offset by U.S. dollar-denominated financing costs and by the Company's hedging activities. TransCanada 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 financing costs.

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 Alberta System and Foothills operations. Certain of the realized gains and losses on these derivatives 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.

TransCanada 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.

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, 2010, the Company had designated as a net investment hedge U.S. dollar-denominated debt with a carrying value of $9.8 billion (US$9.8 billion) (2009 $7.9 billion (US$7.6 billion)) and a fair value of $11.3 billion (US$11.4 billion) (2009 $9.8 billion (US$9.3 billion)). At December 31, 2010, $181 million was included in Intangibles and Other Assets (2009 $96 million) 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)*	**2010** Fair Value[(1)]	**2010** Notional or Principal Amount	2009 Fair Value[(1)]	2009 Notional or Principal Amount
U.S. dollar cross-currency swaps (maturing 2011 to 2016)	**179**	**US 2,800**	86	US 1,850
U.S. dollar forward foreign exchange contracts (maturing 2011)	**2**	**US 100**	9	US 765
U.S. dollar options (matured in 2010)			1	US 100
	181	**US 2,900**	96	US 2,715

(1) Fair values equal carrying values.

VaR Analysis

TransCanada uses a Value-at-Risk (VaR) methodology to estimate the potential impact from its exposure to market risk on its liquid open positions. VaR represents the potential change in pre-tax earnings over a given holding period for a specified confidence level. The VaR number used by TransCanada is calculated assuming a 95 per cent confidence level that the daily change resulting from normal market fluctuations in its liquid open 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.

TransCanada'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 regulated natural gas pipelines, as the nature of the rate-regulated pipeline business reduces the impact of market risks. TransCanada'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. TransCanada's consolidated VaR was $12 million at December 31, 2010 (2009 $12 million).

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.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at the Balance Sheet date, without taking into account security held, consisted of accounts receivable, the fair value of derivative assets and notes, loans and advances receivable. The carrying amounts and fair values of these financial assets, except amounts for derivative assets, are included in Accounts Receivable and Other in the Non-Derivative Financial Instruments Summary table located in the Fair Values section below. Letters of credit and cash are the primary types of security provided to support these amounts. The majority of counterparty credit exposure is with counterparties that are investment grade. At December 31, 2010, there were no significant amounts past due or impaired.

At December 31, 2010, the Company had a credit risk concentration of $317 million (2009 $334 million) due from a creditworthy counterparty. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's parent company.

TransCanada 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 TransCanada's exposure to non-creditworthy counterparties.

As a level of uncertainty continues to exist in the global financial markets, TransCanada continues to closely monitor and reassess the creditworthiness of its counterparties. This has resulted in TransCanada reducing or mitigating its exposure to certain counterparties where it was deemed warranted and permitted under contractual terms. As part of its ongoing operations, TransCanada must balance its market and counterparty credit risks when making business decisions.

Calpine and certain of its subsidiaries filed for bankruptcy protection in Canada or 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 onto shippers on these systems in 2008 and 2009. In 2010, the Company accrued an additional pre-tax gain of $15 million related to expected future proceeds with respect to the GTNC and Portland claims.

Liquidity Risk

Liquidity risk is the risk that TransCanada will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity risk is to ensure that sufficient cash and credit facilities are available to meet its operating, financing and capital expenditure obligations when due, under both normal and stressed economic conditions.

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 in the Capital Management section below.

At December 31, 2010, the Company had unutilized committed revolving bank lines of US$1.0 billion, $2.0 billion and US$0.8 billion maturing in November 2011, December 2012 and December 2012, respectively. The Company has also maintained continuous access to the Canadian commercial paper market on competitive terms.

Capital Management

The primary objective of capital management is to ensure TransCanada has strong credit ratings to support its businesses and maximize shareholder value. In 2010, the overall objective and policy for managing capital remained unchanged from the prior year.

TransCanada 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 comprises 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 TransCanada's joint ventures.

The total capital managed by the Company was as follows:

December 31 *(millions of dollars)*	**2010**	2009
Notes payable	**2,081**	1,678
Long-term debt	**17,922**	16,664
Junior subordinated notes	**985**	1,036
Cash and cash equivalents	**(660)**	(896)
Net debt	**20,328**	18,482
Non-controlling interests	**1,157**	1,174
Shareholders' equity	**16,727**	15,759
Total equity	**17,884**	16,933
	38,212	35,415

Fair Values

Certain financial instruments included in Cash and Cash Equivalents, Accounts Receivable, Intangibles and Other Assets, 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 and applying a discounted cash flow valuation model. The fair value of power, natural gas and oil products derivatives, and of available-for-sale investments, has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used.

The fair value of the Company's Notes Receivable is calculated by discounting future payments of interest and principal using forward interest rates. Long-Term Debt was estimated based on quoted market prices for the same or similar debt instruments. Credit risk has been taken into consideration when calculating the fair value of derivatives, Notes Receivable and Long-Term Debt.

Non-Derivative Financial Instruments Summary

The carrying and fair values of non-derivative financial instruments were as follows:

	2010		2009	
December 31 *(millions of dollars)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Financial Assets[1]				
Cash and cash equivalents	**764**	**764**	997	997
Accounts receivable and other[2][3]	**1,555**	**1,595**	1,432	1,483
Available-for-sale assets[2]	**20**	**20**	23	23
	2,339	**2,379**	2,452	2,503
Financial Liabilities[1][3]				
Notes payable	**2,092**	**2,092**	1,687	1,687
Accounts payable and deferred amounts[4]	**1,436**	**1,436**	1,538	1,538
Accrued interest	**367**	**367**	377	377
Long-term debt	**17,922**	**21,523**	16,664	19,377
Junior subordinated notes	**985**	**992**	1,036	976
Long-term debt of joint ventures	**866**	**971**	965	1,025
	23,668	**27,381**	22,267	24,980

(1) Consolidated Net Income in 2010 included gains of $8 million (2009 gains of $6 million) for fair value adjustments related to interest rate swap agreements on US$250 million (2009 US$250 million) of long-term debt. There were no other unrealized gains or losses from fair value adjustments to the financial instruments.

(2) At December 31, 2010, the Consolidated Balance Sheet included financial assets of $1,271 million (2009 $966 million) in Accounts Receivable, $40 million (2009 nil) in Other Current Assets and $264 million (2009 $489 million) in Intangibles and Other Assets.

(3) Recorded at amortized cost except for $250 million (2009 $250 million) of Long-Term Debt, which is adjusted to fair value.

(4) At December 31, 2010, the Consolidated Balance Sheet included financial liabilities of $1,406 million (2009 $1,513 million) in Accounts Payable and $30 million (2009 $25 million) in Deferred Amounts.

The following tables detail the remaining contractual maturities for TransCanada's non-derivative financial liabilities, including both the principal and interest cash flows at December 31, 2010:

Contractual Repayments of Financial Liabilities[1]

		Payments Due by Period			
(millions of dollars)	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Notes payable	2,092	2,092			
Long-term debt	17,922	894	2,012	2,034	12,982
Junior subordinated notes	985				985
Long-term debt of joint ventures	866	65	148	99	554
	21,865	3,051	2,160	2,133	14,521

(1) The anticipated timing of settlement of derivative contracts is presented in the Derivatives Financial Instrument Summary below.

Interest Payments on Financial Liabilities

		Payments Due by Period			
(millions of dollars)	Total	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Long-term debt	16,721	1,140	2,190	1,973	11,418
Junior subordinated notes	410	63	126	126	95
Long-term debt of joint ventures	381	48	90	80	163
	17,512	1,251	2,406	2,179	11,676

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2010 is as follows:

December 31	2010			
(all amounts in millions unless otherwise indicated)	**Power**	**Natural Gas**	**Foreign Exchange**	**Interest**
Derivative Financial Instruments Held for Trading(1)				
Fair Values(2)				
Assets	**$169**	**$144**	**$8**	**$20**
Liabilities	**$(129)**	**$(173)**	**$(14)**	**$(21)**
Notional Values				
Volumes(3)				
Purchases	**15,610**	**158**		
Sales	**18,114**	**96**		
Canadian dollars				**736**
U.S. dollars			**US 1,479**	**US 250**
Cross-currency			**47/US 37**	
Net unrealized (losses)/gains in the year(4)	**$(32)**	**$27**	**$4**	**$43**
Net realized gains/(losses) in the year(4)	**$77**	**$(42)**	**$36**	**(74)**
Maturity dates	**2011-2015**	**2011-2015**	**2011-2012**	**2011-2016**
Derivative Financial Instruments in Hedging Relationships(5)(6)				
Fair Values(2)				
Assets	**$112**	**$5**	**$**	**$8**
Liabilities	**$(186)**	**$(19)**	**$(51)**	**$(26)**
Notional Values				
Volumes(3)				
Purchases	**16,071**	**17**		
Sales	**10,498**			
U.S. dollars			**US 120**	**US 1,125**
Cross-currency			**136/US 100**	
Net realized losses in the year(4)	**$(9)**	**$(35)**	**$**	**$(33)**
Maturity dates	**2011-2015**	**2011-2013**	**2011-2014**	**2011-2015**

(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 and natural gas derivatives are in GWh and billion cubic feet (Bcf), respectively.

(4) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power and natural gas are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships is initially recognized in Other Comprehensive (Loss)/Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(5) 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 a notional amount of US$250 million. In 2010, net realized gains on fair value hedges were $4 million and were included in Interest Expense. In 2010, the Company did not record any amounts in Net Income related to ineffectiveness for fair value hedges.

(6)

In 2010, Net Income included a gain of $1 million for changes in the 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 2010, 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, 2010. 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	2011	2012 and 2013	2014 and 2015	2016 and Thereafter
Derivative financial instruments held for trading					
Assets	341	221	102	17	1
Liabilities	(337)	(191)	(121)	(24)	(1)
Derivative financial instruments in hedging relationships					
Assets	306	76	204	26	
Liabilities	(282)	(146)	(120)	(16)	
	28	(40)	65	3	

Derivative Financial Instruments Summary

Information for the Company's derivative financial instruments for 2009 is as follows:

December 31	2009				
(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	$150	$107	$5	$	$25
Liabilities	$(98)	$(112)	$(5)	$(66)	$(68)
Notional Values					
Volumes[(2)]					
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)]	$3	$(5)	$1	$3	$27
Net realized gains/(losses) in the year[(3)]	$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[(1)]					
Assets	$175	$2	$	$	$15
Liabilities	$(148)	$(22)	$	$(43)	$(50)
Notional Values					
Volumes[(2)]					
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[(3)]	$156	$(29)	$	$	$(37)
Maturity dates	2010-2015	2010-2014		2010-2014	2010-2020

(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) Realized and unrealized gains and losses on held-for-trading derivative financial instruments used to purchase and sell power, natural gas and fuel oil are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative financial instruments held for trading are included in Interest Expense and Interest Income and Other, respectively. The effective portion of unrealized gains and losses on derivative financial instruments in hedging relationships is initially recognized in Other Comprehensive (Loss)/Income and reclassified to Revenues, Interest Expense and Interest Income and Other, as appropriate, as the original hedged item settles.

(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. In 2009, realized gains on fair value hedges 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 changes in the 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.

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)*	**2010**	2009
Current		
Other current assets	**273**	315
Accounts payable	**(337)**	(340)
Long term		
Intangibles and other assets	**374**	260
Deferred amounts	**(282)**	(272)

Derivative Financial Instruments of Joint Ventures Included in the Derivative Financial Instruments Summary tables 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 $48 million at December 31, 2010 (2009 $105 million). These contracts mature from 2011 to 2015. The Company's proportionate share of the notional sales volumes of power associated with this exposure was 3,772 GWh at December 31, 2010 (2009 6,312 GWh). The Company's proportionate share of the notional purchased volumes of power associated with this exposure was 2,322 GWh at December 31, 2010 (2009 2,747 GWh).

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy. In Level I, the fair value of assets and liabilities is determined by reference to quoted prices in active markets for identical assets and liabilities. In Level II, determination of the fair value of assets and liabilities includes valuations using inputs, other than quoted prices, for which all significant outputs are observable directly or indirectly. This category includes fair value determined using valuation techniques, such as option pricing models and extrapolation using observable inputs. In Level III, determination of the fair value of assets and liabilities is based on inputs that are not readily observable and are significant to the overall fair value measurement. Long-dated commodity transactions in certain markets 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.

There were no transfers between Level I and Level II in 2010 and 2009. Financial assets and liabilities measured at fair value, including both current and non-current portions, are categorized as follows:

	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total	
December 31 *(millions of dollars, pre-tax)*	**2010**	2009	**2010**	2009	**2010**	2009	**2010**	2009
Natural Gas Inventory			**49**					