TRANSCANADA PIPELINES LTD
Form 40-F
February 15, 2013

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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, 2012** Commission File Number **1-8887**

TRANSCANADA PIPELINES LIMITED

(Exact Name of Registrant as specified in its charter)

Canada
(Jurisdiction of incorporation or organization)

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

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

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

TransCanada PipeLine USA Ltd., 717 Texas Street
Houston, Texas, 77002-2761; (832) 320-5201
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered pursuant to section 12(b) of the Act: **None**

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

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act: **Debt Securities**

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

o 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, 2012, 4,000,000 Cumulative Redeemable First Preferred Shares Series U and 4,000,000 Cumulative Redeemable First Preferred Shares Series Y were issued and outstanding.
738,507,894 common shares which are all owned by TransCanada Corporation

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data 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

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

Form	Registration No.
F-9	333-177789

EXPLANATORY NOTE

An amendment to this Form 40-F shall be filed to include the TransCanada PipeLines Limited ("TCPL") Annual Information Form for the year ended December 31, 2012. The amendment shall be filed no later than the date the Annual Information Form is required pursuant to home country requirements.

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 TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements 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 95 through 151 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements included herein.

B. Management's Discussion and Analysis

For management's discussion and analysis, see pages 1 through 94 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements included herein.

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

For management's report on internal control over financial reporting, see "Report of Management" that accompanies the Audited Consolidated Financial Statements on page 95 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements included herein.

UNDERTAKING

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

DISCLOSURE CONTROLS AND PROCEDURES

For information on disclosure controls and procedures, see "Other Information Controls and Procedures" in Management's Discussion and Analysis on pages 76 and 77 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements.

AUDIT COMMITTEE FINANCIAL EXPERT

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

CODE OF ETHICS

The Registrant has adopted a code of business ethics for its directors, officers, employees and contractors. The Registrant's code is available on its website at www.transcanada.com. No waivers have been granted from any provision of the code during the 2012 fiscal year.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

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 up to $250,000, 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 $250,000 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 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 2012 and 2011 fiscal years.

($ millions)	**2012**	**2011**
Audit fees	**$5.7**	$6.9
audit of the annual consolidated financial statements		
services related to statutory and regulatory filings or engagements		
review of interim consolidated financial statements and information contained in various prospectuses and other offering documents		
Audit-related fees	**0.1**	0.2
services related to the audit of the financial statements of certain TransCanada post-retirement and post-employment plans		
Tax fees	**0.5**	0.4
Canadian and international tax planning and tax compliance matters, including the review of income tax returns and other tax filings		
All other fees	**0.6**	0.1
review of information system design procedures		
services related to vendor analytics and environmental compliance credits		
Total fees	**$6.9**	$7.6

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 66 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements.

IDENTIFICATION OF THE AUDIT COMMITTEE

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

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

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are *forward-looking* are based on certain assumptions and on what we know and expect today and generally include words like *anticipate*, *expect*, *believe*, *may*, *will, should*, *estimate* or other similar words.

Forward-looking statements in this document may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- expected costs for planned projects, including projects under construction and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this document.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties including the following:

Assumptions

inflation rates, commodity prices and capacity prices

timing of debt issuances and hedging

regulatory decisions and outcomes

foreign exchange rates

interest rates

tax rates

planned and unplanned outages and the use of our pipeline and energy assets

integrity and reliability of our assets

access to capital markets

anticipated construction costs, schedules and completion dates

acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our U.S. pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- 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
- cybersecurity
- interest and foreign exchange rates
- weather

technological developments

economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC).

You should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

SIGNATURES

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

TRANSCANADA PIPELINES LIMITED

Per: /s/ DONALD R. MARCHAND

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

Date: February 15, 2013

DOCUMENTS FILED AS PART OF THIS REPORT

13.1	Management's Discussion and Analysis (included on pages 1 through 94 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements).
13.2	2012 Audited Consolidated Financial Statements (included on pages 95 through 151 of the TCPL 2012 Management's Discussion and Analysis and Audited Consolidated Financial Statements), including the auditors' report thereon.
EXHIBITS	
23.1	Consent of KPMG LLP, Independent Registered Public Accounting Firm.
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.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Management's discussion and analysis

February 11, 2013

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada PipeLines Limited. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2012. Comparative figures, which were previously presented in accordance with Canadian generally accepted accounting principles (as defined in Part V of the Canadian Institute of Chartered Accountants Handbook), have been adjusted as necessary to be compliant with our accounting policies under United States generally accepted accounting principles (U.S. GAAP), which we adopted effective January 1, 2012.

This MD&A should be read with our accompanying December 31, 2012 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. GAAP.

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About this document

Throughout this MD&A, the terms, *we*, *us, our* and *TCPL* mean TransCanada PipeLines Limited and its subsidiaries.

Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 94.

All information is as of February 11, 2013 and all amounts are in Canadian dollars, unless noted otherwise.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are *forward-looking* are based on certain assumptions and on what we know and expect today and generally include words like *anticipate*, *expect*, *believe*, *may*, *will*, *should*, *estimate* or other similar words.

Forward-looking statements in this MD&A may include information about the following, among other things:

- anticipated business prospects
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows
- expected costs for planned projects, including projects under construction and in development
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- expected outcomes with respect to legal proceedings, including arbitration
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- inflation rates, commodity prices and capacity prices
- timing of debt issuances and hedging

regulatory decisions and outcomes

foreign exchange rates

interest rates

tax rates

planned and unplanned outages and the use of our pipeline and energy assets

integrity and reliability of our assets

access to capital markets

anticipated construction costs, schedules and completion dates

acquisitions and divestitures.

Risks and uncertainties

- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our U.S. pipelines business
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration
- performance of our counterparties
- changes in the political environment
- 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
- cybersecurity
- interest and foreign exchange rates
- weather
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the U.S. Securities and Exchange Commission (SEC).

You should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

See *Supplementary information* beginning on page 152 for other consolidated financial information on TCPL for the last three years.

You can also find more information about TCPL in our annual information form and other disclosure documents, which are available on SEDAR (www.sedar.com).

About our business

With over 60 years of experience, TCPL 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. We are a wholly owned subsidiary of TransCanada Corporation (TransCanada).

THREE CORE BUSINESSES

We operate our business in three segments Natural Gas Pipelines, Oil Pipelines and Energy. We also have a non-operational corporate segment consisting of corporate and administrative functions that provide support and governance to our operational business segments.

Our $48 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 31 U.S. states, Mexico and three South American countries.

at December 31 (millions of $)	**2012**	**2011**	**% change**
Total assets			
Natural Gas Pipelines	**23,210**	23,161	-
Oil Pipelines	**10,485**	9,440	11%
Energy	**13,157**	13,269	(1%)
Corporate	**2,483**	2,196	13%
Total	**49,335**	48,066	3%

year ended December 31 (millions of $)	**2012**	**2011**	**% change**
Total revenue			
Natural Gas Pipelines	**4,264**	4,244	1%
Oil Pipelines	**1,039**	827	26%
Energy	**2,704**	2,768	(2%)
Corporate	**-**	-	-
Total	**8,007**	7,839	2%

year ended December 31 (millions of $)	2012	2011	% change
Comparable EBIT 1			
Natural Gas Pipelines	**1,808**	1,952	(7%)
Oil Pipelines	**553**	457	21%
Energy	**620**	907	(32%)
Corporate	**(111)**	(100)	(11%)
Total	**2,870**	3,216	(11%)

1 Comparable EBIT is a non-GAAP measure see page 12 for details.

Common shares outstanding average

(millions)	
2012	738
2011	678
2010	662

as at February 6, 2013 Common shares	Issued and outstanding

	746 million

Preferred shares	Issued and outstanding
Series U	4 million
Series Y	4 million

A LONG-TERM STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

TCPL's vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy

1 Maximize the full-life value of our infrastructure assets and commercial positions

Our strategy at a glance

Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low-risk business model.

Our pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flows and earnings.

In Energy, efficient, large-scale power generation facilities supply power markets through long-term power purchase and sale agreements and low-volatility shorter-term commercial arrangements. Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrate our commitment to clean, sustainable energy.

2 Commercially develop and build new asset investment programs

Our strategy at a glance

We are developing quality projects under our current $12 billion capital program. These will contribute incremental earnings as our investments are placed in service.

Our expertise in managing construction risks and maximizing capital productivity ensures a disciplined approach to quality, cost and schedule, resulting in superior service for our customers and quality returns to shareholders.

As part of our growth strategy, we rely on this expertise and our regulatory, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.

3 Cultivate a focused portfolio of high quality development options

Our strategy at a glance

We focus on pipelines and energy growth initiatives in core regions of North America.

We are assessing opportunities to acquire energy infrastructure that complements our existing pipeline network and provides access to new supply and market regions.

We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks are acceptable.

4 Maximize our competitive strengths

Our strategy at a glance

We are continually developing competitive strengths in areas that directly drive long-term shareholder value.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give TCPL our competitive edge.

Strong leadership: scale, presence, operating capabilities, strategy development; expertise in regulatory, legal and financing support.

High quality portfolio: a low-risk business model that maximizes the full-life value of our long-life assets and commercial positions.

Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.

Financial expertise: excellent reputation for consistent financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizeable amounts of competitively priced capital to support our growth.

Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors both the upside and the risks to build trust and support.

2012 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under U.S. GAAP because we believe they improve our ability to compare results between reporting periods, and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be comparable to similar measures provided by other companies.

See page 12 for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents.

Highlights

Comparable EBITDA (earnings before interest, taxes, depreciation and amortization), comparable EBIT (earnings before interest and taxes), comparable earnings and funds generated from operations are all non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $, except per share amounts)	**2012**	**2011**	**2010**
Income			
Revenue	**8,007**	7,839	6,852
Comparable EBITDA	**4,245**	4,544	3,686
Net income attributable to common shares	**1,338**	1,503	1,240
per common share basic and diluted	**$1.81**	$2.22	$1.87
Comparable earnings	**1,369**	1,536	1,364
Operating cash flow			
Funds generated from operations	**3,259**	3,360	3,109
Decrease/(increase) in working capital	**287**	207	(292)
Net cash provided by operations	**3,546**	3,567	2,817
Investing activities			
Capital expenditures	**2,595**	2,513	4,376
Equity investments	**652**	633	597
Acquisitions, net of cash acquired	**214**	-	-
Balance sheet			
Total assets	**49,335**	48,066	46,595
Long-term debt	**18,913**	18,659	18,016
Junior subordinated notes	**994**	1,016	993
Preferred shares	**389**	389	389
Common shareholders' equity	**17,915**	17,543	14,988

Comparable earnings and net income

Comparable earnings

Comparable earnings in 2012 were $167 million lower than 2011.

The decrease in comparable earnings was the result of:

- lower earnings from Western Power reflecting a full year of the Sundance A PPA force majeure
- lower equity income from Bruce Power because of increased outage days
- recording lower Canadian Mainline net income in 2012 which excluded incentive earnings and reflected a lower investment base
- lower earnings from Great Lakes which reflected lower revenues as a result of lower rates and uncontracted capacity
- lower earnings from ANR because of lower transportation and storage revenues, lower incidental commodity sales and higher operating costs
- lower earnings from U.S. Power due to lower realized prices, higher load serving costs and reduced water flows at the hydro facilities

These decreases were partially offset by:

- a full year of revenue from Guadalajara pipeline
- higher Keystone Pipeline System revenues primarily due to higher contracted volumes and a full year of earnings being recorded in 2012 compared to 11 months in 2011
- incremental earnings from Cartier Wind and Coolidge

lower comparable interest expense mainly because of lower interest expense on amounts due to TransCanada, partially offset by new debt issuances in November 2011, March 2012 and August 2012

higher comparable interest income and other, mainly because we realized higher gains on derivatives used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income

lower comparable income taxes due to lower pre-tax earnings.

2011 comparable earnings were $172 million higher than 2010 and comparable EBIT was $690 million higher than 2010 resulting from:

- higher Natural Gas Pipelines comparable EBIT increased because we placed Bison in service in January and Guadalajara in service in June 2011, general, administrative and support costs were lower, and business development spending was lower. This was partly offset by lower revenues from certain U.S. pipelines and the negative impact of a weaker U.S. dollar.
- higher Oil Pipelines comparable EBIT as we began recording earnings from the Keystone Pipeline System in February 2011
- higher Energy comparable EBIT because realized power prices at Western Power were higher, combined with a full year of earnings from Halton Hills and the start up of Coolidge. This was partly offset by lower contributions from Bruce B, Natural Gas Storage and U.S. Power
- higher comparable interest expense, mainly because:
  - we placed the Keystone Pipeline System and other new assets in service, which reduced capitalized interest
  - we issued U.S. dollar-denominated debt in June and September 2010, which increased interest expense
  - partly offset by the realization of gains on derivatives used to manage our exposure to rising interest rates and a weaker U.S. dollar reduced our U.S. dollar-denominated interest expense
- lower comparable interest income and other, mainly due to reduced gains on the derivatives we used to manage our exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher comparable income taxes, because pre-tax earnings were higher and higher positive income tax adjustments in 2010 compared to 2011.

Net income attributable to common shares

Net income attributable to common shares in 2012 was $1,338 million (2011 $1,503 million; 2010 $1,240 million).

Net income includes comparable earnings discussed above as well as other specific items which are excluded from comparable earnings. The following specific items were recognized in net income in 2010 to 2012:

- a negative after-tax charge of $15 million ($20 million pre-tax) was included in net income following the Sundance A power purchase arrangement (PPA) arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011
- a negative after-tax charge of $127 million ($146 million pre-tax) was included in net income after we recorded a valuation provision against the loan to the Aboriginal Pipeline Group (APG) relating to the Mackenzie Gas Project (MGP). This charge was recorded in fourth quarter 2010.
- the impact of certain risk management activities each year. See page 12 for explanation of specific items in Non-GAAP measures.

Cash flow

Funds generated from operations

Funds generated from operations was three per cent lower this year primarily for the same reasons comparable earnings were lower, as described above.

Funds used in investing

Capital expenditures

We invested $2.6 billion in capital projects this year as part of our ongoing capital program. This program is a key part of our strategy to optimize the value of our existing assets and develop new, complementary assets in high demand areas.

Capital expenditures

year ended December 31, 2012 (millions of $)	
Natural Gas Pipelines	1,389
Oil Pipelines	1,145
Energy	24
Corporate	37

Equity investments and acquisitions

In 2012, we invested $0.7 billion into Bruce Power for capital projects which included the restart of Units 1 and 2 and the West Shift Plus life extension outage on Unit 3. We also spent $0.2 billion on the acquisition of the remaining 40 per cent interest in CrossAlta.

Balance sheet

We maintained a strong balance sheet while growing our total assets by over $3 billion since 2010. At December 31, 2012, common equity represented 45 per cent of our capital structure.

Dividends

Dividend reinvestment plan

Under our dividend reinvestment plan (DRP), eligible holders of TransCanada common or preferred shares and preferred shares of TCPL, can reinvest their dividends and make optional cash payments to buy TransCanada common shares.

Before April 28, 2011, common shares purchased with reinvested cash dividends were satisfied with shares issued from treasury at a discount to the average market price in the five days before dividend payment. Beginning with the dividends declared in April 2011, common shares purchased with reinvested cash dividends are satisfied with shares acquired on the open market without discount. The increase in dividends paid on common shares (see below) is, in part, the result of this change combined with the impact of an annual five per cent increase in the dividend rate between 2010 and 2012.

Quarterly dividends on our common shares

The dividend declared for the quarter ending March 31, 2013 is equal to the quarterly dividend to be paid on TransCanada's issued and outstanding common shares at the close of business on March 29, 2013.

Quarterly dividends on our preferred shares

Series U $0.70 (for the period ending April 30, 2013)

Series Y $0.70 (for the period ending May 1, 2013)

Cash dividends year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Common shares	**1,226**	1,163	1,088
Preferred shares	**22**	22	22

Refer to the Results section in each business segment and the Financial Condition section of this MD&A for further discussion of these highlights.

OUTLOOK

Earnings

We anticipate earnings in 2013 to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and fewer planned outage days at Bruce A
- higher New York capacity prices as a result of a September 2012 Federal Energy Regulatory Commission (FERC) order
- higher earnings from the Alberta System due to a higher investment base
- return to service of Sundance A in fall 2013
- acquisition of several Ontario Solar assets over the course of 2013 and 2014

A favourable decision by the National Energy Board (NEB) on the Canadian Mainline Business and Services Restructuring Proposal and 2012 and 2013 Mainline Final Tolls Application (Canadian Restructuring Proposal) would have a positive impact on 2013 earnings.

These increases in earnings will be partially offset by higher operating, maintenance and administration (OM&A), general and administrative and corporate and governance costs, lower EBIT from U.S. Pipelines and higher outage days at Bruce B.

EBIT

Natural Gas Pipelines

EBIT from the Natural Gas Pipelines segment in 2013 will be affected by regulatory decisions and the timing of those decisions, including decisions about the Canadian Restructuring Proposal. Earnings will also be affected by market conditions, which drive the level of demand and rates we are able to secure for our services. Today's North American natural gas market is characterized by strong natural gas production, low natural gas prices and low values for storage and transportation services, which we expect to have a negative impact on U.S. Pipelines revenue in 2013.

Until we receive the NEB's decision with respect to the Canadian Restructuring Proposal, earnings from the Canadian Mainline will continue to reflect the last approved rate of return on common equity (ROE) of 8.08 per cent on deemed common equity of 40 per cent, and will exclude incentive earnings that have enhanced Canadian Mainline's earnings in recent years. If the 2012 and 2013 tolls are approved as filed, earnings in 2013 will reflect a higher ROE equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent for 2012 and 2013. We also expect higher earnings from the Alberta System because of continued growth in the investment base.

Oil Pipelines

We expect 2013 EBIT from the Oil Pipelines segment to be consistent with 2012 as the Gulf Coast Project, currently under construction, is expected to be placed in service at the end of 2013.

Energy

We expect 2013 EBIT from the Energy segment to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and lower planned outage days at Bruce A
- a full year of operations from the Gros-Morne Wind farm, which was placed in service in fourth quarter 2012
- higher New York capacity prices as a result of the September 2012 FERC order affecting pricing rules for new entrants
- the return to service of Sundance A in fall 2013
- the acquisition of several Ontario Solar assets in 2013
- incremental earnings from acquiring the remaining 40 per cent interest in CrossAlta in late December 2012.

We expect these increases to be partially offset by higher outage days at Bruce B and higher Bruce A and B pension and staff costs.

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 affected by fluctuations in commodity prices.

Consolidated capital expenditures, equity investments and acquisitions

We spent $3.5 billion on capital expenditures, equity investments and acquisitions in 2012 and expect to spend approximately $6.4 billion in 2013 primarily related to Keystone XL, Gulf Coast Project, Alberta System expansions, the Tamazunchale Extension project, the Topolobampo and Mazatlan pipelines in Mexico and maintenance projects on our natural gas pipelines.

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- comparable earnings
- comparable EBITDA
- comparable EBIT
- comparable interest expense
- comparable interest income and other
- comparable income taxes
- funds generated from operations.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other entities.

EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting interest and other financial charges, income taxes, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a better measure of our performance and an effective tool for evaluating trends in each segment. It is calculated in the same way as EBITDA, less depreciation and amortization.

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a better measure of our consolidated operating cashflow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period. See page 6 for a reconciliation to net cash provided by operations.

Comparable measures

We calculate the comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income taxes	income tax expense/(recovery)

Our decision not to include a specific item is subjective and made after careful consideration. These may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments

- gains or losses on sales of assets
- legal and bankruptcy settlements, and
- write-downs of assets and investments.

We calculate comparable earnings by excluding the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

Reconciliation of non-GAAP measures

year ended December 31 (millions of $, except per share amounts)	**2012**	**2011**	**2010**
Comparable EBITDA	**4,245**	4,544	3,686
Depreciation and amortization	**(1,375)**	(1,328)	(1,160)
Comparable EBIT	**2,870**	3,216	2,526
Other income statement items			
Comparable interest expense	**(997)**	(1,046)	(754)
Comparable interest income and other	**86**	60	94
Comparable income taxes	**(472)**	(565)	(387)
Net income attributable to non-controlling interests	**(96)**	(107)	(93)
Preferred share dividends	**(22)**	(22)	(22)
Comparable earnings	**1,369**	1,536	1,364
Specific items (net of tax)			
Sundance A PPA arbitration decision	**(15)**	-	-
Risk management activities[1]	**(16)**	(33)	3
Valuation provision for MGP	**-**	-	(127)
Net income attributable to common shares	**1,338**	1,503	1,240
Comparable interest expense	**(997)**	(1,046)	(754)
Specific item:			
Risk management activities[1]	**-**	2	-
Interest expense	**(997)**	(1,044)	(754)
Comparable interest income and other	**86**	60	94
Specific item:			
Risk management activities[1]	**(1)**	(5)	-
Interest income and other	**85**	55	94
Comparable income taxes	**(472)**	(565)	(387)
Specific item:			
Sundance A PPA arbitration decision	**5**	-	-
Risk management activities[1]	**6**	19	(4)
Valuation provision for MGP	**-**	-	19
Income taxes expense	**(461)**	(546)	(372)

1

year ended December 31 (millions of $)	**2012**	**2011**	**2010**

Canadian Power	**4**	1	-
U.S. Power	**(1)**	(48)	2
Natural Gas Storage	**(24)**	(2)	5
Interest rate	**-**	2	-
Foreign exchange	**(1)**	(5)	-
Income taxes attributable to risk management activities	**6**	19	(4)
Total gains (losses) from risk management activities	**(16)**	(33)	3

EBITDA and EBIT by business segment

year ended December 31, 2012 (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**2,741**	**698**	**903**	**(97)**	**4,245**
Depreciation and amortization	**(933)**	**(145)**	**(283)**	**(14)**	**(1,375)**
Comparable EBIT	**1,808**	**553**	**620**	**(111)**	**2,870**

year ended December 31, 2011 (millions of $)					
Comparable EBITDA	2,875	587	1,168	(86)	4,544
Depreciation and amortization	(923)	(130)	(261)	(14)	(1,328)
Comparable EBIT	1,952	457	907	(100)	3,216

year ended December 31, 2010 (millions of $)					
Comparable EBITDA	2,816	-	969	(99)	3,686
Depreciation and amortization	(913)	-	(247)	-	(1,160)
Comparable EBIT	1,903	-	722	(99)	2,526

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facitilities and other businesses across Canada, the U.S. and Mexico. We serve approximately 15 per cent of the U.S. demand and more than 80 per cent of the Canadian demand on a daily basis by connecting major natural gas supply basins and markets through:

- wholly owned natural gas pipelines 57,000 km (35,500 miles), and
- partially owned natural gas pipelines 11,500 km (7,000 miles).

We have regulated natural gas storage facilities in Michigan with a total capacity of 250 Bcf, making us one of the largest providers of natural gas storage and related services in North America.

Strategy at a glance

Optimizing the value of our existing natural gas pipelines systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

We are also pursuing new pipeline projects to add incremental value to our business. Our key areas of focus include greenfield development opportunities, such as infrastructure for liquefied natural gas (LNG) exports and within Mexico, as well as other opportunities that connect natural gas pipelines to emerging Canadian and U.S. shale gas and other supplies to market and play a critical role in meeting the increasing demand for natural gas in North America.

We are the operator of all of the following natural gas pipelines and storage assets except for Iroquois.

		length	description	effective ownership
	Canadian pipelines			
1	Alberta System	24,337 km (15,122 miles)	Gathers and transports natural gas within Alberta and Northeastern B.C., and connects with Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,101 km (8,762 miles)	Transports natural gas from the Alberta/Saskatchewan border to the Québec/Vermont border, and connects with other natural gas pipelines in Canada and the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. midwest, Pacific northwest, California and Nevada	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montreal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
	ANR			
5	Pipeline	16,656 km (10,350 miles)	Transports natural gas from producing fields in Texas and Oklahoma, from offshore and onshore regions of the Gulf of Mexico and from the U.S. midcontinent, for delivery mainly to Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	100%
5a	Storage	250 billion cubic feet	Provides regulated underground natural gas storage service from facilities located in Michigan	
6	Bison	487 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
7	Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the Western Canada Sedimentary Basin (WCSB) and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 83.3 per cent of the system through the combination of our 75 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	83.3%
8	Great Lakes	3,404 km (2,115 miles)	Connects with ANR and the Canadian Mainline near Emerson, Manitoba, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 69.0 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 33.3 per cent interest in TC PipeLines, LP	69%
9	Iroquois	666 km (414 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. northeast	44.5%

		length	description	effective ownership
	U.S. pipelines			
10	North Baja	138 km (86 miles)	Transports natural gas between Ehrenberg, Arizona and Ogilby, California, and connects with a third-party natural gas system on the California/Mexico border. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	33.3%
11	Northern Border	2,265 km (1,407 miles)	Transports natural gas through the U.S. Midwest, and connects with Foothills near Monchy, Saskatchewan. We effectively own 16.7 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	16.7%
12	Portland	474 km (295 miles)	Connects with TQM near East Hereford, Québec, to deliver natural gas to customers in the U.S. northeast	61.7%
13	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to Wadsworth, Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 33.3 per cent of the system through our 33.3 per cent interest in TC PipeLines, LP	33.3%
	Mexican pipelines			
14	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo to Guadalajara in Mexico	100%
15	Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potos, Mexico	100%
	Under construction			
16	Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Mexico. Connects to the Topolobampo Pipeline Project	100%
17	Tamazunchale Pipeline Extension	235 km (146 miles)	Extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro, Mexico	100%
18	Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas from Chihuahua to Topolobampo, Mexico	100%
	In development			
19	Alaska Pipeline Project	2,737 km (1,700 miles)	To transport natural gas from Prudhoe Bay to Alberta, or from Prudhoe Bay to LNG facilities in south-central Alaska. We have an agreement with ExxonMobil to jointly advance the projects	

20	Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas-producing region near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.
21	Prince Rupert Gas Transmission Project	750 km* (466 miles)	To deliver natural gas from North Montney gas producing region near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.

* Pipe lengths are estimates as final route is still under design

RESULTS

Natural Gas Pipelines results

Comparable EBITDA, comparable EBIT and EBIT are all non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Canadian Pipelines			
Canadian Mainline	**994**	1,058	1,054
Alberta System	**749**	742	742
Foothills	**120**	127	135
Other Canadian (TQM[1], Ventures LP)	**29**	34	33
Canadian Pipelines comparable EBITDA	**1,892**	1,961	1,964
Depreciation and amortization[2]	**(715)**	(711)	(704)
Canadian Pipelines comparable EBIT	**1,177**	1,250	1,260
U.S. and International (in US$)			
ANR	**254**	306	309
GTN[3]	**112**	131	171
Great Lakes[4]	**62**	101	109
TC PipeLines, LP[1,5]	**74**	85	81
Other U.S. pipelines (Iroquois[1], Bison[6], Portland[7])	**111**	111	61
International (Gas Pacifico/INNERGY[1], Guadalajara[8], Tamazunchale, TransGas[1])	**112**	77	42
General, administrative and support costs[9]	**(8)**	(9)	(31)
Non-controlling interests[10]	**161**	173	144
U.S. Pipelines and International comparable EBITDA	**878**	975	886
Depreciation and amortization[2]	**(218)**	(214)	(203)
U.S. Pipelines and International comparable EBIT	**660**	761	683
Foreign exchange	**-**	(7)	22
U.S. Pipelines and International comparable EBIT (Cdn$)	**660**	754	705
Business Development comparable EBITDA and EBIT	**(29)**	(52)	(62)
Natural Gas Pipelines comparable EBIT	**1,808**	1,952	1,903
Summary			
Natural Gas Pipelines comparable EBITDA	**2,741**	2,875	2,816
Depreciation and amortization[2]	**(933)**	(923)	(913)
Natural Gas Pipelines comparable EBIT	**1,808**	1,952	1,903
Specific items:			
Valuation provision for MGP[11]	**-**	-	(146)
Natural Gas Pipelines EBIT	**1,808**	1,952	1,757

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.

2 Does not include depreciation and amortization from equity investments as these are already reflected in equity income.

3 Reflects our direct ownership interest of 75 per cent starting in May 2011 and 100 per cent prior to that date.

4 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 percent is held by TC PipeLines, LP.

5 Our ownership interest in TC PipeLines, LP went from 38.2 per cent to 33.3 per cent starting in May 2011. The TC PipeLines, LP results include our effective ownership since May 2011 of 8.3 per cent of both GTN and Bison.

6 Reflects our direct ownership of 75 per cent of Bison starting in May 2011 when 25 per cent was sold to TC PipeLines, LP, and 100 per cent since January 2011 when Bison was placed in service.

7 Represents our 61.7 per cent ownership interest.

8 Included as of June 2011.

9 General, administrative and support costs associated with some of our pipelines, including $17 million for the start up of Keystone in 2010.

10 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

11 We recorded a valuation provision of $146 million in 2010 for our advances to the APG for MGP.

Canadian Pipelines

Comparable EBITDA and net income for our rate-regulated Canadian Pipelines are affected by our ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and taxes also impact comparable EBITDA but do not impact net income as they are recovered in revenue on a flow-through basis.

Net income for the Canadian Mainline this year was $59 million lower than 2011 because there was no incentive earnings mechanism in place in 2012 and the average investment base was lower as annual depreciation outpaced our capital investment. Despite higher incentive earnings, 2011 net income was $21 million lower than 2010 because ROE was higher in 2010 (8.08 per cent in 2011 compared to 8.52 per cent in 2010), and the average investment base was also lower in 2011.

Net income for the Alberta System was $8 million higher than 2011 because of a growing investment base, as new natural gas supply in northeastern B.C. and western Alberta was developed and connected to the Alberta System. This was partially offset by lower incentive earnings. Net income in 2011 was $2 million higher than 2010, mainly due to a growing investment base.

Comparable EBITDA and EBIT for the Canadian pipelines reflect the net income variances discussed above as well as variances in depreciation, financial charges and income taxes which are recovered in revenue on a flow-through basis and, therefore, do not impact net income.

Net income
Year ended December 31 (millions of $)

Average investment base
Year ended December 31 (millions of $)

U.S. Pipelines and International

EBITDA for our U.S. operations is affected by contracted volume levels, volumes delivered and the rates charged, as well as by the cost of providing services, including OM&A and other costs, and property taxes.

ANR is also affected by the contracting and pricing of its storage capacity and incidental commodity sales. ANR's pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of its business.

Comparable EBITDA for the U.S. and international pipelines was US$878 million in 2012, or US$97 million lower than 2011. This reflects the net effect of:

- lower revenue at Great Lakes because of lower rates and uncontracted capacity
- lower transportation and storage revenues at ANR, along with lower incidental commodity sales
- higher OM&A and other costs at ANR
- incremental earnings from the Guadalajara pipeline which started operations in June 2011.

Comparable EBITDA for U.S. and international pipelines was $975 million in 2011 which was $89 million higher than 2010. This was due to the net effect of:

- Bison starting operations in January 2011
- Guadalajara starting operations in June 2011
- lower general, administrative support costs in 2011

lower revenues at Great Lakes and GTN in 2011.

Depreciation and amortization

Depreciation and amortization was $10 million higher in 2012 than in 2011, and was $10 million higher in 2011 than in 2010, mainly because Bison began operations in January 2011 and Guadalajara began operations in June 2011.

Business development

Business development expenses in 2012 were $23 million lower than last year because of lower expenses associated with the Alaska Pipeline Project. Expenses were $10 million lower in 2011 compared to 2010 mainly because the State of Alaska increased its business development reimbursement from 50 per cent to 90 per cent as of July 31, 2010.

OUTLOOK

Canadian Pipelines

Earnings

Earnings are affected most significantly by changes in investment base, ROE and capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

Until we receive the NEB's decision with respect to the Canadian Restructuring Proposal, earnings from the Canadian Mainline will continue to reflect the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent, and will exclude the opportunity for incentive earnings that have enhanced Canadian Mainline's earnings in recent years as no incentive arrangement is currently in place. If the 2012 and 2013 tolls are approved as filed, earnings in 2013 will reflect a higher ROE equivalent to an ROE of 12 per cent on deemed common equity of 40 per cent for 2012 and 2013.

We expect the Alberta System's investment base to continue to grow as new natural gas supply in northeastern B.C. and western Alberta continues to be developed and is connected to it. We expect the growing investment base to have a positive impact on earnings in 2013.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

U.S. Pipelines

Earnings

Earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader macroeconomic conditions that might impact demand from certain customers or market segments. Currently, the North American natural gas market is characterized by low natural gas prices and low values for storage and transportation services, which we expect to have a negative impact on U.S. Pipelines revenue in 2013.

Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulators decisions.

Mexico Pipelines

2013 earnings are expected to be consistent with 2012 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital expenditures

We spent a total of $1.4 billion in 2012 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $1.9 billion in 2013 primarily on Alberta System expansion projects, the Tamazunchale Pipeline Extension, the Topolobampo and Mazatlan pipelines in Mexico, and maintenance projects on our natural gas pipelines. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines in North America that connects locations where gas is produced or interconnects with other pipelines connected to end customers such as local distribution companies, power generation facilities and other users. The network includes meter stations that record how much natural gas comes on the network and how much comes off at the delivery locations, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline, and the pipelines themselves that transport natural gas under high pressure.

Regulation, tolls and cost recovery

We are regulated in Canada by the NEB, in the U.S. by the FERC and in Mexico by the Comisión Reguladora de Energía or Energy Regulatory Commission (CRE). The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow recovery of costs to operate the network by collecting tolls, or payments, for services. These costs include OM&A costs, income and property taxes, interest on debt, depreciation expense to recover invested capital, and a return on the capital invested. The regulator reviews our costs to ensure they are prudent, and approves the tolls based on recovering these costs.

Within their respective jurisdictions, the FERC and CRE approve maximum transportation rates. These rates are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for investors. The pipeline may negotiate these rates with shippers.

Sometimes we and our shippers enter into agreements, or settlements, for tolls and cost recovery, which may include mutually beneficial performance incentives. The regulator must approve a settlement for it to be put into effect.

Generally, the Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover the variance between actual and expected revenues and costs in future years. The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower tolls if they consider returns to be too high. Our Mexico pipelines are also regulated and have approved tariffs, services and related rates. However, the contracts underpinning the facilities in Mexico are long-term negotiated rate contracts and not subject to further regulatory approval.

Business environment and strategic priorities

In this section, we discuss the environment in which we conduct our natural gas pipelines business, including our strategic priorities for our natural gas pipelines business.

The North American natural gas pipeline network has been developed to connect supply to market. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies and changing demand.

We have a significant pipeline footprint in the WCSB and transport approximately 70 per cent of its production to markets within and outside of Alberta. Our pipelines also source natural gas, to a less significant degree, from the other major basins including the Appalachian, Rockies, Williston, Haynesville, Fayetteville, and Gulf of Mexico.

Increasing supply

The WCSB spans almost all of Alberta and extends into B.C., Saskatchewan, Yukon and Northwest Territories and is Canada's primary source of natural gas. The WCSB is currently estimated to have 125 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of almost 200 trillion cubic feet. The total WCSB resource base has more than doubled in the recent past with the advent of technology that can economically access unconventional gas plays in the basin. We expect production from the WCSB to decrease slightly in 2013 and then grow over the next decade.

The Montney and Horn River shale play formations in northeastern B.C. are also part of the WCSB and have recently become a significant source of natural gas. We expect production from these sources, currently 1.5 Bcf/d, to grow to approximately 5 Bcf/d by 2020, depending on natural gas prices and the economics of exploration and production.

The primary sources of natural gas in the U.S. are the U.S. shale plays, Gulf of Mexico and the Rockies. The U.S. shales are the biggest area of growth which we estimate will meet almost 50 per cent of the overall North American gas supply by 2020. Of the shale plays in the U.S, the Marcellus, Haynesville, Barnett, Eagle Ford and Fayetteville shale plays are the major supply sources.

The supply of natural gas in North America is forecast to increase significantly over the next decade (by approximately 15 Bcf/d by 2020), and is expected to continue to increase over the long term for several reasons:

- New technology, such as horizontal drilling in combination with multi-stage hydraulic fracturing or fracking, is allowing companies to access unconventional resources economically. This is increasing the technically accessible resource base of existing basins and opening up new producing regions, such as the Marcellus and Utica shale in the U.S. northeast, and the Montney and Horn River shale areas in northeastern B.C.

- These new technologies are also being applied to existing oil fields where further recovery of the resource is now possible. High oil prices, particularly compared to North American natural gas prices, has resulted in an increase in exploration and production of liquid-rich hydrocarbon basins. There is often associated gas in these plays (for example, the Bakken oil fields) which increases the overall gas supply for North America.

The development of shale gas basins that are located close to traditional existing markets, particularly in the U.S., has led to an increase in the number of supply choices and is changing traditional gas pipeline flow patterns. On some of our pipelines, such as the Canadian Mainline, ANR, and Great Lakes, there has been a reduction in long-haul, long-term firm contracted capacity and a shift to shorter-distance, shorter-term contracts.

While the increase in supply, particularly in northeastern B.C., has created opportunities for us to build new pipeline infrastructure to move the natural gas to markets, the development of alternative supply sources in the U.S., and particularly in the U.S. northeast, has caused pipelines that have traditionally served markets in this area (including ours), to reconfigure their flow patterns from continental routes to more regional ones.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which have supported increasing demand and is expected to continue. Examples include:

- the use of natural gas in the development of the Alberta oil sands
- increased natural gas-fired power generation driven by conversion from coal
- industrial growth in both Canada and the U.S.
- increased exports to Mexico to fuel new power generation facilities
- increased use of natural gas used in petrochemical and industrial facilities in both Canada and the U.S.

Natural gas producers are also looking to sell natural gas to global markets, which would involve connecting natural gas supplies to new LNG export terminals proposed primarily along the west coast of B.C., and on the U.S. Gulf of Mexico coast. Assuming the receipt of all necessary regulatory and other approvals, these facilities are expected to become operational in the second half of this decade. The addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

More competition

Changes in supply and demand have resulted in growing pipeline infrastructure and increased competition for transportation services throughout North America. More pipeline capacity was added to the continental pipeline network between 2008 and 2011 than in any comparable time period in industry history, and gas supply areas that were once constrained, like the U.S. Rockies and east Texas, now have several paths to reach markets.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, as well as opportunities to connect new markets, while satisfying increasing demand for natural gas within existing markets.

We are also focused on adapting our existing assets to the changing gas flow dynamics.

The Canadian Mainline has traditionally sourced its natural gas primarily from the WCSB and delivered it to eastern markets. New supply located closer to the eastern markets has reduced demand for gas from the WCSB that, in turn, has reduced revenues from long haul transportation. As a result, overall tolls on the Mainline have increased and caused a reduction in the Canadian Mainline's competitive position. We are looking for opportunities to increase its market share in Canadian domestic markets, however, we expect to continue to face competition for both the eastern Canada and U.S. northeast markets. Our current application with the NEB seeks to restructure tolls on the Canadian Mainline to correspond with pipeline flow and usage patterns resulting from new supply and demand dynamics. The hearing on our application concluded in December 2012 and a decision is expected in late first quarter or early second quarter of 2013.

The Alberta System is the major natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in Western Canada to domestic and export markets. It faces competition for connection to supply, particularly in northeastern B.C., where the largest new source of natural gas has access to two existing competing pipelines. Connections to new supply and new or growing demand supports new capital expansions of the Alberta System. We expect supply in the WCSB to grow from its current level of approximately 14 Bcf/d to approximately 17 Bcf/d by 2020. The WCSB has an enormous remaining supply potential, but how much is produced, and how quickly, will be influenced by many factors, including transportation costs, the extent of the demand and local market price and basin-on-basin price differentials.

ANR has a very broad geographical footprint, with diverse market and supply access that includes 250 Bcf of natural gas storage, which is a major driver of ANR's revenues. ANR's supply of natural gas comes from many sources including the Gulf of Mexico, Mid-Continent, Rockies, Marcellus/ Utica and the WCSB. Demand served by this pipeline includes markets in Michigan, Wisconsin, Illinois, Indiana and Ohio. Many of ANR's supply and market regions are also served by competing interstate and intrastate natural gas pipelines.

ANR has demonstrated its adaptability to changing market dynamics by identifying opportunities and investing in its system to accommodate the market's demands for services that are counter to traditional flow patterns. This has resulted in increased bi-directional flows and shorter haul services in some of its supply and market areas.

Although the unseasonably warm winter weather and lack of storage demand negatively impacted ANR in 2012, we expect an increased demand for pipeline transportation broadly in the U.S. resulting in a positive impact to ANR because of the following factors:

- a return to average weather conditions
- the increase in gas-fired power generation due to coal switching to gas and coal plant retirements
- LNG exports from the Gulf of Mexico and growth in the industrial sector such as petrochemicals.

GTN is supplied with natural gas from the WCSB and the Rockies. It 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. GTN has significant long term contracts and is currently operating under a rate settlement which started in January 2012 and expires at the end of December 2015. As a result, GTN's revenues are subject to variation primarily as a result of capacity sold above its current contracted amount.

Great Lakes competes for natural gas transportation customers with pipelines that transport gas from the WCSB and natural gas sourced in the U.S. Great Lakes has experienced significant non-renewals of its long haul capacity in the past few years and its contracts are for shorter terms than in the past. Great Lakes revenues were also negatively impacted in 2012 by a warm winter and historically high storage levels that decreased its throughput. Demand for Great Lakes capacity changes with seasonal market conditions and we expect a return to average winter weather will increase throughput due to storage demand. Great Lakes is required to file a rate case no later than November 1, 2013, and this provides the opportunity for rate and tariff changes in response to current market conditions.

We are continually assessing our existing natural gas pipelines assets, and have reviewed the possibility of converting existing infrastructure from gas service to crude oil. We received NEB approval in 2007 to convert one of our Canadian Mainline gas pipelines to crude oil service for the original Keystone project. We have determined that a further conversion of portions of the Canadian Mainline from natural gas to crude oil to serve eastern markets is both technically and economically feasible. The oil pipeline group is assessing the commercial interest in such a conversion.

We are also focused on capturing new opportunities resulting from the changing supply and demand dynamics. In 2012, we undertook the following new projects:

- we completed and placed in service approximately $650 million in pipeline projects to expand the Alberta System.
- we reached an agreement with Shell to build and operate the proposed $4 billion Coastal GasLink pipeline to move WCSB gas to Shell Canada Limited's proposed west coast LNG project near Kitimat, B.C.
- we were awarded $1.9 billion for new pipeline infrastructure projects to meet the growing demand for natural gas in Mexico
- we proposed a $1.0 billion to $1.5 billion expansion to the Alberta System in northeast B.C. to connect to both the Prince Rupert Gas Transmission Project and to additional North Montney supplies.

In January 2013, we were selected by Progress Energy Canada Ltd, to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission Project that will transport natural gas from northeastern B.C. to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C.

SIGNIFICANT EVENTS

Canadian Pipelines

Alberta System

This year we completed and placed in service approximately $650 million in pipeline projects to expand the Alberta System. This included completing the Horn River project in May, which extended the Alberta System into the Horn River shale play in B.C.

In 2012, the NEB approved approximately $640 million in additional expansions, including the Leismer-Kettle River Crossover project, a 30-inch, 77 km (46 mile) pipeline. This project will cost an estimated $160 million and is intended to increase capacity to meet demand in northeastern Alberta. As of December 31, approximately $330 million in additional projects were awaiting approval, including the $100 million Chinchaga Expansion and the $230 million Komie North project that would extend the Alberta System further into the Horn River area. On January 30, 2013, the NEB issued its recommendation to the Governor-in-Council that the proposed Chinchaga Expansion component of that project be approved, but denied the proposed Komie North Extension component. All applications awaiting approval as of the end of 2012 have now been addressed.

Canadian Mainline

An NEB hearing began in June 2012 to address our application to change the business structure and the terms and conditions of service for the Canadian Mainline, including tolls for 2012 and 2013. The hearing concluded in December 2012 and a decision is not expected until late first quarter or early second quarter 2013.

We received NEB approval in May to build new pipeline facilities to provide Southern Ontario with additional natural gas supply from the Marcellus shale basin. Supply began moving on November 1, 2012.

In response to requests to bring additional Marcellus shale gas into Canada, we held an additional open season for firm transportation service on the Canadian Mainline that ended in May 2012. We were able to accommodate an additional 50 MMcf/d from the Niagara meter station to Kirkwall effective November 1, 2012 with the potential for an additional 350 MMcf/d of incremental volumes for November 1, 2015 subject to finalizing precedent agreements with the interested parties.

Projects

Coastal GasLink

We were selected in June by Shell and its partners to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion pipeline will transport natural gas from the Montney gas-producing region near Dawson Creek, B.C. to LNG Canada's recently announced LNG export facility near Kitimat, B.C. The LNG Canada project is a joint venture led by Shell, with partners Korea Gas Corporation, Mitsubishi Corporation and PetroChina Company Limited. The approximate 650 km (404 mile) pipeline is expected to have an initial capacity of more than 1.7 Bcf/d and be placed in service toward the end of the decade, subject to a final investment decision to be made by LNG Canada subsequent to obtaining final regulatory approvals.

Prince Rupert Gas Transmission Project

We have been selected by Progress Energy Canada Ltd (Progress), to design, build, own and operate the proposed $5 billion Prince Rupert Gas Transmission Project. This proposed pipeline will transport natural gas primarily from the North Montney gas-producing region near Fort St John, B.C., to the proposed Pacific Northwest LNG export facility near Prince Rupert, B.C. We expect to finalize definitive agreements with Progress in early 2013 leading to an in-service date in late 2018. A final investment decision to construct the project is expected to be made by Progress following final regulatory approvals.

Alberta System expansion projects

We continue to advance pipeline development projects in B.C. and Alberta to transport new natural gas supply. We have filed applications with the NEB to expand the Alberta System to accommodate requests for additional natural gas transmission service throughout the northwest and northeast portions of the WCSB. In addition, we propose to further extend the Alberta System in northeast B.C. to connect both to the Prince Rupert Gas Transmission Project and to additional North Montney gas supplies. This new infrastructure will allow the Pacific Northwest LNG export facility, located on the west coast of B.C., to access both the North Montney supplies as well as other WCSB gas supply. Initial capital cost estimates are approximately $1 billion to $1.5 billion, with an initial in-service date targeted for the end of 2015. We have incremental firm commitments to transport approximately 3.4 Bcf/d from western Alberta and northeastern B.C. by 2015.

Tamazunchale Pipeline Extension Project

In February 2012, we signed a contract with Mexico's Comisión Federal de Electricidad (CFE) for the approximately $500 million Tamazunchale Pipeline Extension Project. The project, which is supported by a 25-year contract with CFE, is a 235 km (146 mile) 30 inch pipeline with a capacity of 630 MMcf/d. Engineering, procurement and construction contracts have all been signed and construction related activities have begun. We expect the pipeline to be in service in the first quarter of 2014.

Topolobampo Pipeline Project

In November, CFE also awarded us the Topolobampo pipeline, from Chihuahua to Topolobampo, Mexico. The project, which is supported by a 25 year contract with CFE, is a 530 km (329 mile) 30 inch pipeline with a capacity of 670 MMcf/d. We estimate total costs to be US$1 billion, and expect it to be in service in mid-2016.

Mazatlan Pipeline Project

In November, CFE also awarded us the Mazatlan pipeline, from El Oro to Mazatlan, Mexico. The project, which is also supported by a 25 year contract with CFE and interconnects with the Topolobampo project, is a 413 km (257 mile) 24 inch pipeline with a capacity of 200 MMcf/d. We estimate total costs to be US$400 million, and expect it to be in service in fourth quarter 2016.

Alaska Pipeline Project

We and the Alaska North Slope producers have agreed on a work plan to evaluate options to commercialize North Slope natural gas resources through an LNG option. We received approval in May from the State of Alaska to suspend and preserve our activities on the Alaska/Alberta route and focus on the LNG alternative, which allowed us to defer our obligation to file for a FERC certificate for the Alberta route beyond fall 2012 (our original deadline). In September 2012, we solicited interest in a natural gas pipeline as part of the LNG option and there were a number of non-binding expressions of interest from potential shippers from a broad range of industry sectors in North America and Asia.

Regulatory filings

Canadian Pipelines

We filed a comprehensive restructuring proposal with the NEB in September 2011 for the Canadian Mainline. The proposal is intended to enhance the competitiveness of the Canadian Mainline and transportation from the WCSB, and includes a request for 2012 and 2013 tolls that align with the proposed changes to our business structure and the terms and conditions of service on the Canadian Mainline. The NEB established interim tolls for 2012 based on the approved 2011 final tolls. We do not expect a decision on the Canadian Restructuring Proposal until late first quarter or early second quarter 2013.

The current settlements for the Alberta and Foothills systems expired at the end of 2012. Final tolls for 2013 will be determined through either new settlements or rate cases and any orders resulting from the NEB's decision on the Canadian Restructuring Proposal.

U.S. Pipelines

ANR Pipeline Company rates were established at the beginning of 1997. ANR can, but is not required to, file for new rates. The FERC issued orders in 2012 approving ANR's sale of its offshore assets to a newly created wholly owned subsidiary, TC Offshore LLC, allowing TC Offshore LLC to operate these assets as a stand-alone interstate pipeline. TC Offshore LLC began commercial operations on November 1, 2012. ANR Storage Company secured a settlement with its shippers that the FERC approved on August 20, 2012. ANR Storage Company owns 56 Bcf of the total ANR storage capacity.

GTN has a FERC-approved settlement agreement for transportation rates that is effective from January 2012 to the end of December 2015. The GTN settlement includes a moratorium on the filing of future rate proceedings until December 2015. GTN is required to file for new rates to go into effect January 1, 2016.

Northern Border secured a final settlement agreement with its shippers that the FERC approved with an effective date of January 1, 2013. The settlement rates for long-haul transportation are approximately 11 per cent lower than 2012 rates and depreciation was lowered from 2.4 to 2.2 per cent. The settlement also includes a three-year moratorium on filing cases or challenging the settlement rates but Northern Border must initiate another rate proceeding within five years.

Great Lakes has a FERC-approved settlement agreement in place. It can file for new rates at any time, but must file no later than November 1, 2013.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 70 for information about general risks that affect the company as a whole.

WCSB supply for downstream connecting pipelines

Although we have diversified our sources of natural gas supply, many of our North American natural gas pipelines and transmission infrastructure assets depend on supply from the WCSB. There is competition for this supply from several downstream pipelines, demand within Alberta, and in the future, demand for proposed pipelines for LNG exports from the west coast of B.C. The WCSB has considerable reserves, but how much of it is actually produced will depend on many variables, including the price of gas, basin-on-basin competition, downstream pipeline tolls, demand within Alberta and the overall value of the reserves, including liquids content.

Market access to other supply

We compete for market share with other natural gas pipelines. New supply areas being developed closer to traditional markets have reduced the competitiveness of our long haul pipelines, and may continue to do so. The long-term competitiveness of our pipeline systems will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition

We face competition from other pipeline companies seeking to connect similar supply and/or access to market. Most, if not all, long haul natural gas pipelines in North America are affected by the fundamental changes in flow dynamics resulting from new shale supply developments. The future success of new projects, such as connecting pipelines to LNG export facilities or development of Mexico gas pipeline infrastructure, is anticipated to be highly competitive.

Demand for pipeline capacity

Demand for a pipeline's capacity is ultimately the key driver that enables transportation services to be sold. Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Demand and supply in new locations often creates opportunities for new infrastructure, but it may also change flow patterns and potentially impact the utilization of existing assets. For example, the proposed LNG facilities on the west coast of B.C. have the potential to reduce demand for capacity on pipelines that transport WCSB supply to other markets. Our natural gas pipelines may be challenged to sell available transportation capacity as transportation contracts expire on our existing pipeline assets, as they have, for example, on the Great Lakes system. We expect our U.S. natural gas pipelines to become more exposed to the potential for revenue variability due to rapidly evolving supply dynamics, competition and trends toward shorter-term contracting by shippers.

Several factors influence demand for pipeline capacity:

- the price of natural gas is a key driver for development and exploration of the resource. The current low gas prices in North America may slow drilling activities which in turn diminishes production levels, particularly in dry gas fields where the extra revenue generated from the entrained liquids is not available.

- large producers often diversify their portfolios by developing several basins, but this is influenced by actual costs to develop the resource as well as economic access to markets and cost of the necessary pipeline infrastructure. Basin-on-basin competition impacts the extent and timing of a resource play's development, which in turn drives changes in demand for pipeline capacity.

- there is growing regulatory and public scrutiny over the environmental impacts of fracking. Changes in regulations that apply to fracking could impact the costs and pace of development of natural gas plays.

- growing pipeline infrastructure, changes in supply sources, and unutilized capacity on many pipelines have led to a contraction of regional basis differentials (the differences in market prices paid for natural gas between different gas receipt and delivery points), which has led to changes in the way many pipeline systems are being used. As a result, many pipeline companies are moving to restructure their business models, rate designs and services to adapt to the changing flow dynamics.

Regulatory risk

Decisions by regulators can have an impact on the approval, construction, operation and financial performance of our natural gas pipelines. We manage these risks through rate and facility applications and negotiated settlements, where possible. Public opinion about natural gas pipeline development can also have an impact on the regulatory approval process for new gas pipeline assets. We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business and work closely with our stakeholders in the development of the assets.

Operational

Keeping our pipelines operating is essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced revenue. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly, and repair or replace them whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Oil Pipelines

TCPL's Keystone Pipeline System connects Alberta crude oil supplies to significant U.S. refining markets in Illinois and Oklahoma. The system has a nominal design capacity of 591,000 Bbl/d and is 3,467 km (2,154 miles) long.

Our plan for Keystone XL creates an opportunity for us to transport growing North American crude oil supplies to market. Keystone XL will increase the total capacity of the Keystone Pipeline System to approximately 1.4 million Bbl/d and we have secured long-term, firm contracts in excess of 1.1 million Bbl/d.

The current construction of the Gulf Coast Project will connect the crude oil hub at Cushing, Oklahoma to the U.S. Gulf Coast with an initial capacity of up to 700,000 Bbl/d.

We recently announced the Grand Rapids Pipeline and Northern Courier Pipeline and our expansion of the Keystone Hardisty Terminal. These projects are giving us a competitive position in the growing intra-Alberta crude oil transportation market.

Strategy at a glance

With the increasing production of crude oil in Alberta, new crude oil discoveries in the U.S. and the growing demand for secure, reliable sources of energy, developing new crude oil pipeline capacity is essential.

We continue to focus on contracting and delivering growing North American crude oil supply to key U.S. markets, and are planning to expand our oil pipeline infrastructure by:

- building a new crude oil pipeline from Cushing, Oklahoma to the U.S. Gulf Coast (the Gulf Coast Project)
- adding batch accumulation and pipeline infrastructure at Hardisty, Alberta (Keystone Hardisty Terminal)
- building a new crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska (Keystone XL)
- building the Grand Rapids Pipeline to transport crude oil and diluent between the producing area in northern Alberta and the Edmonton/Heartland region and
- building the Northern Courier Pipeline to transport bitumen and diluent between the Fort Hills mine site and proposed Voyageur Upgrader, north of Fort McMurray, Alberta.

Our proposed conversion of a

portion of the Canadian Mainline from natural gas to crude oil service would connect the eastern Canadian refining market to our oil pipeline infrastructure (Canadian Mainline conversion) and also gives us additional opportunities to expand our oil pipelines business.

We are the operator of all of the following pipelines and properties.

		length	description	ownership
	Oil pipelines			
22	Keystone Pipeline System	3,467 km (2,154 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, and to Cushing, Oklahoma	100%
	Under construction			
23	Cushing Marketlink	Crude oil receipt facilities	To transport crude oil from the Permian Basin producing region in western Texas to the U.S. Gulf Coast refining market on facilities that form part of the Gulf Coast Project	100%
24	Gulf Coast Project	780 km (485 miles)	To transport crude oil from the hub at Cushing, Oklahoma to the U.S. Gulf Coast refinery market. Includes the 76 km (47 mile) Houston Lateral pipeline	100%
25	Keystone Hardisty Terminal	Crude oil terminal	Crude oil terminal to be located at Hardisty, Alberta, providing Western Canadian producers with new crude oil batch accumulation tankage and pipeline infrastructure and access to the Keystone Pipeline System	100%
	In development			
26	Bakken Marketlink	Crude oil receipt facilities	To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
*	Canadian Mainline Conversion		Conversion of a portion of the Canadian Mainline natural gas pipeline system to crude oil service, which will transport crude oil between Hardisty, Alberta and markets in eastern Canada	100%
27	Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil between the producing area northwest of Fort McMurray and the Edmonton/Heartland market region. Project is a partnership with Phoenix Energy Holdings Limited (Phoenix)	50%
28	Keystone XL	1,897 km (1,179 miles)	Pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System to 1.4 million Bbl/d. Awaiting U.S. Presidential Permit decision	100%
29	Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader located north of Fort McMurray, Alberta.	100%

* Not shown on map

RESULTS

Comparable EBITDA, comparable EBIT and EBIT are all non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**[1]
Keystone Pipeline System	**712**	589
Oil Pipeline Business Development	**(14)**	(2)
Oil Pipelines comparable EBITDA	**698**	587
Depreciation and amortization	**(145)**	(130)
Oil Pipelines comparable EBIT	**553**	457
Comparable EBIT denominated as follows		
Canadian dollars	**191**	159
U.S. dollars	**363**	301
Foreign exchange	**(1)**	(3)
Oil Pipelines comparable EBIT	**553**	457

1 Results in 2011 are for 11 months.

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $123 million higher this year than in 2011. This increase reflected higher revenues primarily resulting from:

- higher contracted volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Wood River and Patoka, in Illinois, which came into effect in May 2011
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012
- twelve months of earnings being recorded in 2012 compared to eleven months in 2011.

The Keystone Pipeline System began commercial operations in June 2010, when we began delivering crude oil to Wood River and Patoka in Illinois. We capitalized all cash flows except general, administrative and support costs until February 2011. The NEB initially restricted the operating pressure on the Canadian conversion segment of the pipeline. As a result, we could not operate it at design pressure and throughput capacity was much lower than the initial nominal capacity of 435,000 Bbl/d. The NEB removed the restriction in December 2010 and we made operational modifications in late January 2011 which allowed us to operate at higher pressure and increase throughput capacity.

We began recording EBITDA for the Keystone Pipeline System in February 2011, when we began delivering crude oil to Cushing, Oklahoma.

Business development

Business development expenses this year were $12 million higher than 2011 mainly because of increased business development activity on various development projects.

Depreciation and amortization

Depreciation and amortization was $15 million higher this year than in 2011 because 12 months of depreciation was recorded in 2012 compared to 11 months in 2011.

OUTLOOK

Earnings

We expect 2013 earnings to be consistent with 2012. Earnings are expected to increase over time as projects currently in development are placed in service.

Capital expenditures

We spent a total of $1.1 billion in 2012, and expect to spend $4.1 billion in 2013, mainly related to Keystone XL and the Gulf Coast Project. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

UNDERSTANDING THE OIL PIPELINES BUSINESS

Oil pipelines move crude oil from major sources of supply to refinery markets so the crude oil can be refined into various petroleum products.

Our Keystone Pipeline System connects Alberta crude oil supplies to significant U.S. refining markets in Illinois and Oklahoma. It generates earnings mainly by providing pipeline capacity to shippers on a take-or-pay basis in exchange for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and, when capacity is available, provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by long-term transportation service arrangements negotiated with shippers. These arrangements average 18 years, and provide for the recovery of costs we incur to operate the system.

Business environment

Increasing crude oil supply production in Canada and the U.S. has increased the demand for new crude oil pipeline infrastructure and, as a result, we are pursuing opportunities to connect growing North American crude oil supplies to key markets.

Alberta produces the majority of the crude oil in the WCSB which is the primary source of crude oil supply for the Keystone Pipeline System.

In 2011, the WCSB produced an estimated 1.1 million Bbl/d of conventional crude oil and condensate, and 1.6 million Bbl/d of Alberta oil sands crude oil   a total of approximately 2.7 million Bbl/d. The production of conventional crude oil in western Canada grew for the first time after years of decline.

In its 2012 report, the Alberta Energy Resources Conservation Board estimates there are approximately 170 billion barrels of remaining established conventional and oil sands reserves in Alberta. In June 2012, the Canadian Association of Petroleum Producers forecasted WCSB crude oil supply would increase to 3.6 million Bbl/d by 2015 and to 4.5 million Bbl/d by 2020. Its 2012 forecast for western Canadian production of conventional and unconventional crude oil in 2025 is 885,000 Bbl/d higher than its forecast in 2011.

Oil sands production

Despite increases in production from conventional sources, and new shale oil production (including the Bakken and Cardium formations), the oil sands will continue to make up most of the crude oil production from the WCSB. The Alberta Energy Resources Conservation Board's 2012 report estimates that oil sands capital expenditures increased $2.7 billion in 2011, to $19.9 billion, and predicts that investment will be $21.5 billion in 2012 and $24.7 billion in 2015.

Oil sands projects have very long lives: conservative estimates are 40 years for mining sites and 25 years for in-situ production, and some estimates are considerably higher. That means producers need to secure long-term connectivity to market. The Keystone Pipeline System, including Keystone XL, provides producers with needed pipeline capacity and is largely contracted for an average term of 18 years.

Demand for infrastructure within Alberta

Growth in oil sands production is also driving the need for new intra-Alberta pipelines, like our Grand Rapids Pipeline, that can move crude oil production from the source to market hubs at Edmonton/Heartland and Hardisty, where they can connect with the Keystone Pipeline System, and other pipelines that transport crude oil outside of Alberta, and move diluent from the Edmonton/Heartland region to the producing area in northern Alberta.

Growth in U.S. production

According to the International Energy Agency (IEA) World Energy Outlook report, the U.S. is set to overtake Saudi Arabia as the world's largest oil producer. The IEA projects approximately three million Bbl/d of U.S. shale oil production growth, peaking in approximately 2020 and starting to decline by around 2025.

The Williston Basin, located mainly in North Dakota and Montana, produced more than 600,000 Bbl/d in 2012, and production levels are expected to reach approximately one million Bbl/d by 2014 because of rapid growth in Bakken shale oil production. The Williston Basin is the primary source of crude oil supply for the Bakken Marketlink project.

According to BENTEK Energy, the Permian Basin, located mainly in western Texas, currently produces 1.3 million Bbl/d and will reach 1.8 million Bbl/d by the end of 2016. The Permian Basin is the primary source of crude oil for the Cushing Marketlink project. Growing U.S. production has contributed to increased crude oil supply at the Cushing, Oklahoma market hub and resulted in increased demand for additional pipeline capacity between Cushing and the U.S. Gulf Coast refining market. Our Gulf Coast Project will provide needed pipeline capacity to transport growing crude oil supply at Cushing to the U.S. Gulf Coast.

Even with growth in U.S. crude oil production, the IEA report predicts the U.S. will remain a net importer of crude oil, importing 3.4 million Bbl/d into 2035. Growing production in the west Texas Permian and south Texas Eagle Ford basins, which is primarily light crude oil, is expected to compete with Williston Basin light crude oil production volumes but generally will not compete with Canadian volumes. Gulf Coast refiners will continue to prefer Canadian heavy oil because their refineries are mainly set up to run heavy crude oil and cannot easily switch to running the new light shale oil in large quantities.

Refineries in eastern Canada currently import light crude oil from west Africa and the Middle East, so are better able to handle light shale oil. Many of these refineries have recently begun transporting domestic light crude oil in small quantities by rail, at a cost typically higher than the cost to ship by pipeline. This has created a significant demand for pipelines to connect eastern Canada with growing Bakken and WCSB light crude oil production. We are positioned to meet this need by potentially converting portions of our Canadian Mainline natural gas pipeline system between Alberta and eastern Canada.

SIGNIFICANT EVENTS

Tolls

We filed revised fixed tolls with the NEB and the FERC this year for committed pipeline capacity to Cushing, Oklahoma. The new tolls went into effect on July 1, 2012, and represent the final project costs of the Keystone Pipeline System.

Gulf Coast Project

We announced in February 2012 that what had previously been the Cushing to U.S. Gulf Coast portion of the Keystone XL Pipeline has its own independent value to the marketplace, and that we plan to build it as the stand-alone Gulf Coast Project, which is not part of the Keystone XL Presidential Permit process.

The 36-inch pipeline will extend from Cushing, Oklahoma to the U.S. Gulf Coast. We expect it to have an initial capacity of up to 700,000 Bbl/d, and an ultimate capacity of 830,000 Bbl/d. We estimate the total cost of the project to be US$2.3 billion, and as of December 31, 2012, construction was approximately 35 per cent complete. US$300 million of the total cost is expected to be spent on the Houston Lateral pipeline, a 76 km (47 mile) pipeline that will transport crude oil to Houston refineries.

Construction began in August 2012 and we expect to place the pipeline in service at the end of 2013.

Keystone XL Pipeline

In May 2012, we filed a Presidential Permit application (cross-border permit) with the U.S. Department of State (DOS) for Keystone XL to transport crude oil from the U.S./Canada border in Montana to Steele City, Nebraska. We continued to work collaboratively with the Nebraska Department of Environmental Quality (NDEQ) and various other stakeholders throughout 2012 to determine an alternative route in Nebraska that would avoid the Nebraska Sandhills. We had proposed an alternative route to the NDEQ in April 2012, and then modified the route in response to comments from the NDEQ and other stakeholders.

In September 2012, we submitted a Supplemental Environmental Report to the NDEQ for the proposed re-route, and provided an environmental report to the DOS, required as part of the DOS review of our cross-border permit application.

In January 2013, the NDEQ issued its final evaluation report on our proposed re-route to the Governor of Nebraska. The report noted that the proposed re-route avoids the Nebraska Sandhills, and that construction and operation of Keystone XL is expected to have minimal environmental impacts in Nebraska. On January 22, 2013, the Governor of Nebraska approved our proposed re-route.

The DOS is now completing their environmental and National Interest Determination review process and we are awaiting their decision on our cross-border permit application.

The pipeline will extend from Hardisty, Alberta to Steele City, Nebraska. We estimate the total cost of the project to be US$5.3 billion and, as of December 31, 2012, had invested US$1.8 billion. We expect the pipeline to be in service in late 2014 or early 2015, subject to regulatory approvals.

Marketlink Projects

We have commenced construction on the Cushing Marketlink receipt facilities and expect to begin transporting crude oil supply from the Permian Basin producing region in western Texas to the U.S. Gulf Coast in late 2013 after our Gulf Coast Project is placed in service. Our Bakken Marketlink project will transport crude oil supply from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL which remains subject to regulatory approval.

Keystone Hardisty Terminal

We announced in May 2012 that we had secured binding long-term commitments of more than 500,000 Bbl/d for the Keystone Hardisty Terminal, and are expanding the proposed two million barrel project to a 2.6 million barrel terminal at Hardisty, Alberta, due to strong commercial support.

The terminal will provide new crude oil batch accumulation tankage and pipeline infrastructure for western Canadian producers, and access to the Keystone Pipeline System.

We expect the terminal to be operational in late 2014 and cost approximately $275 million.

Northern Courier Pipeline

We announced in August 2012 that we had been selected by Fort Hills Energy Limited Partnership to design, build, own and operate the proposed Northern Courier Pipeline.

The 90 km (54 mile) pipeline system will transport bitumen and diluent between the Fort Hills mine site and the Voyageur Upgrader, north of Fort McMurray, Alberta. We estimate total capital costs to be $660 million. The pipeline is fully subscribed under long-term contract to service the Fort Hills mine, which is jointly owned by Suncor Energy Inc, Total E&P Canada Ltd. and Teck Resources Limited.

The project is conditional on the Fort Hills project receiving sanctions by the owners of the Fort Hills mine and is subject to regulatory approval.

Grand Rapids Pipeline

We announced in October 2012 that we had entered into binding agreements with Phoenix to develop the Grand Rapids Pipeline in northern Alberta.

The project includes crude oil and diluent lines to transport volumes approximately 500 km (300 miles), between the producing area northwest of Fort McMurray and the Edmonton/Heartland region. It will have the capacity to move up to 900,000 Bbl/d of crude oil and 330,000 Bbl/d of diluent.

We and Phoenix will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Phoenix has entered into a long-term commitment to ship crude oil and diluent.

The Grand Rapids Pipeline system, subject to regulatory approvals, is expected to be placed in service in multiple stages, with initial crude oil service by mid-2015 and the complete system in service by the second half of 2017.

Canadian Mainline conversion

We have determined that it is technically and economically feasible to convert a portion of the Canadian Mainline natural gas pipeline system to crude oil service. The proposed pipeline will deliver crude oil between Hardisty, Alberta and markets in eastern Canada through a combination of converted natural gas pipelines and new construction. We are actively pursuing this project and have begun soliciting input from stakeholders and prospective shippers to determine market acceptance.

BUSINESS RISKS

The following are risks specific to our oil pipelines business. See page 70 for information about general risks that affect the company as a whole, including other operational risks, health, safety and environment (HSE) risks, and financial risks.

Operational

Optimizing and maintaining availability of our oil pipeline is essential to the success of our oil pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced capacity payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

Regulatory

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our oil pipelines. Public opinion about crude oil development and production also has an impact on the regulatory process. There are some individuals and interest groups that are expressing their opposition to crude oil production by opposing the construction of oil pipelines. We manage this risk by continuously monitoring regulatory developments and decisions to determine their possible impact on our oil pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

Investing in large infrastructure projects involves substantial capital commitments, based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays and potentially reduced investment returns.

Crude oil supply and demand for pipeline capacity

Demand for crude oil pipeline capacity is dependent on the level of crude oil supply and demand for refined crude oil products. New producing technologies such as steam assisted gravity drainage and horizontal drilling in combination with fracking are allowing producers to economically increase development of unconventional resources, such as oil sands and shale oil at current crude oil prices, and have resulted in increased demand for new crude oil pipeline infrastructure. A decrease in demand for refined crude oil products could adversely impact the price of oil producers receive for their product. Lower margins for crude oil could mean producers curtail their investment in the development of crude oil supplies. Depending on their severity, these factors would negatively impact the opportunities we have to expand our crude oil pipeline infrastructure and, in the longer term, contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American crude oil transportation market to transport growing WCSB, Williston Basin and Permian Basin crude oil supplies to key U.S. refining markets, we face competition from other pipeline companies and to a lesser extent, rail companies which also seek to transport these crude oil supplies to market. Our success is dependant on our ability to offer and contract transportation services on terms that are market competitive.

Energy

TCPL's Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta.

We own, control or are developing more than 11,800 MW of generation capacity powered by natural gas, nuclear, coal, hydro, wind and solar assets. Our power business in Canada is mainly located in Alberta, Ontario and Québec. Our U.S. power business is located in New York, New England, and Arizona. The assets are largely supported by long-term contracts and some represent low-cost baseload generation, while others are critically located, essential capacity.

We conduct wholesale and retail electricity marketing and trading throughout North America from our offices in Alberta, Ontario and Massachusetts to actively manage our commodity exposure and provide higher returns.

We own or control approximately 156 Bcf of unregulated natural gas storage capacity in Alberta, accounting for approximately one-third of all storage capacity in the province. When combined with the regulated natural gas storage in Michigan (part of the Natural Gas Pipelines segment), we provide approximately 407 Bcf of natural gas storage and related services.

Strategy at a glance

We are focusing on low-cost, long-life electrical infrastructure and natural gas storage assets supported by strong market fundamentals, and the opportunity for long-term contracts with reputable and creditworthy counterparties. Our investment in natural gas, nuclear, wind, hydro-power and solar generating facilities demonstrates our commitment to clean, sustainable energy.

The growth in demand for power in North America is expected to provide the opportunity to participate in new generation and other power infrastructure projects. Current low natural gas prices make natural gas generation a very cost-competitive option to meet the growing demand in the markets we serve.

Natural gas storage will continue to serve market needs and will play an important role in balancing supply and demand as additional gas supplies are connected to North American and world markets.

1 Includes facilities under development.

We are the operator of all of our Energy assets, except for the Sheerness, Sundance A and Sundance B PPAs, Cartier Wind, Bruce A and B and Portlands Energy.

		generating capacity (MW)	type of fuel	description	location	ownership
	Canadian Power 8,070 MW of power generation capacity (including facilities in development)					
	Western Power 2,636 MW of power supply in Alberta and the western U.S.					
30	Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
31	Cancarb	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TCPL facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
32	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
33	Coolidge[1]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
34	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
35	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
36	Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
37	Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
37	Sundance B PPA (Owned by ASTC Power Partnership[2])	353[3]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
	Eastern Power 2,950 MW of power generation capacity (including facilities in development)					
38	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
39	Cartier Wind	366[3]	wind	Five wind power projects	Gaspésie, Québec	62%
40	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
41	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
42	Portlands Energy	275[3]	natural gas	Combined-cycle plant	Toronto, Ontario	50%

		generating capacity (MW)	type of fuel	description	location	ownership
	Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
43	Bruce A	1,462[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
43	Bruce B	1,022[3]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
	U.S. Power 3,755 MW of power generation capacity					
44	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
45	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
46	Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology	Queens, New York	100%
47	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs	New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers)	100%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity					
48	CrossAlta	68 Bcf[4]		Underground facility connected to Alberta System	Crossfield, Alberta	100%
49	Edson	50 Bcf		Underground facility connected to Alberta System	Edson, Alberta	100%
	In development					
50	Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
51	Ontario Solar	86	solar	Nine solar projects from Canadian Solar Solutions Inc. We expect to acquire the first two projects in the first half of 2013, and the remaining seven projects in 2013 to late 2014	Southern Ontario and New Liskeard, Ontario	100%

1 Located in Arizona, results reported in Canadian Power   Western Power.

2 We have a 50 per cent interest in ASTC Power Partnership, which has a PPA in place for 100 per cent of the production from the Sundance B power generating facilities.

3 Our share of power generation capacity.

4 Reflects the acquisition of an additional 27 Bcf of working gas storage capacity in December 2012.

RESULTS

Comparable EBITDA, and comparable EBIT are non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Canadian Power			
Western Power[1]	**335**	483	212
Eastern Power[2]	**345**	297	212
Bruce Power	**14**	110	173
General, administrative and support costs	**(48)**	(43)	(38)
Canadian Power comparable EBITDÂ	**646**	847	559
Depreciation and amortization[4]	**(152)**	(141)	(114)
Canadian Power comparable EBIT̂	**494**	706	445
U.S. Power (US$)			
Northeast Power[5]	**257**	314	335
General, administrative and support costs	**(48)**	(41)	(32)
U.S. Power comparable EBITDA	**209**	273	303
Depreciation and amortization	**(121)**	(109)	(116)
U.S. Power comparable EBIT	**88**	164	187
Foreign exchange	**-**	(4)	7
U.S. Power comparable EBIT(Cdn$)	**88**	160	194
Natural Gas Storage			
Alberta Storage	**77**	84	136
General, administrative and support costs	**(10)**	(6)	(8)
Natural Gas Storage comparable EBITDÂ	**67**	78	128
Depreciation and amortization[4]	**(10)**	(12)	(13)
Natural Gas Storage comparable EBIT̂	**57**	66	115
Business development comparable EBITDA and EBIT	**(19)**	(25)	(32)
Energy comparable EBIT̂	**620**	907	722
Summary			
Energy comparable EBITDÂ	**903**	1,168	969
Depreciation and amortization[4]	**(283)**	(261)	(247)
Energy comparable EBIT̂	**620**	907	722

1 Includes Coolidge starting in May 2011.

2
Includes Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011 and Montagne- Sèche starting in November 2011; Halton Hills starting in September 2010.

3
Includes our share of equity income from our equity accounted for investments in ASTC Power Partnership, Portlands Energy, Bruce Power and CrossAlta up to December 18, 2012. On December 18, 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent.

4
Does not include depreciation and amortization of equity investments.

5
Includes phase two of Kibby Wind starting in October 2010.

Comparable EBITDA for Energy was $903 million in 2012, or $265 million lower than 2011. This reflected the net effect of:

- decreased Western Power earnings due to the Sundance A PPA force majeure
- incremental earnings from Cartier Wind in Eastern Power and Coolidge in Western Power
- lower equity income from Bruce Power due to increased planned outage days
- decreased U.S. Power earnings because of lower realized power prices, higher load serving costs and reduced water flows at the TC Hydro facilities.

OUTLOOK

Earnings

We expect 2013 earnings from the Energy segment to be higher than 2012, mainly due to the following:

- incremental earnings from Bruce A Units 1 and 2 and fewer planned outage days at Bruce A
- a full year of operations from Gros-Morne which was placed in service in fourth quarter 2012
- higher New York capacity prices as a result of the September 2012 FERC order affecting pricing rules for new entrants
- the acquisition of several of the Ontario Solar assets beginning in early 2013
- we acquired the remaining 40 per cent interests in CrossAlta in December 2012
- the return to service of Sundance A in fall 2013
- offset by higher outage days at Bruce B and higher pension and staff costs at Bruce A and B.

Although a significant portion of Energy's output is sold under long-term contracts, power that is sold under shorter-term forward arrangements or at spot prices will continue to be affected by fluctuations in commodity prices. Fluctuations in Alberta, New England and New York power prices will affect Energy's earnings in 2013, and winter/summer natural gas price spreads will affect earnings in Gas Storage. Timing of the return of the Sundance A units may also have an impact on Western Power's earnings in late 2013.

Weather, unplanned outages, regulatory changes and the overall stability of the energy industry may also affect earnings in 2013.

Western Power

Alberta power market fundamentals are strong and new power capacity and transmission projects are being developed to meet the significant growth in demand. Consumption has been growing since 2009, mirroring economic growth since the recession. The outlook for forward oil prices supports ongoing investment in the oil sands and the associated development is expected to underpin continuing economic growth and increased power demand. Average Alberta power demand in 2012 was almost three per cent higher than 2011. The Alberta Electric System Operator is forecasting that demand will continue to grow at a similar rate over the next 10 years, and estimates that about 6,000 MW of new generation will be required. We expect to participate in new generation additions and other power infrastructure projects to meet Alberta's growing demand. Despite this rising demand, average power prices in Alberta in 2012 ($64/MWh) were lower than 2011 ($77/MWh). Spot market power prices are a function of many factors, including supply/demand conditions and natural gas prices. The supply of power is for the most part dictated by the performance of the coal fleet and wind availability, while power demand is highly influenced by the weather and seasonal factors. Natural gas prices, which at times were below $2/GJ, contributed to the low power prices, especially in offpeak and windy onpeak periods. The return of the Sundance A units in late 2013, the addition of a power transmission line to Montana in 2013 and a large combined cycle plant under construction for 2015 could have a negative effect on Alberta power prices in the near and medium term.

Eastern Power

Our existing energy assets in Ontario are largely insulated from changes in the market price of power through contracts with the Ontario Power Authority (OPA). The Ontario Independent Electricity System Operator forecasts growth in the demand for power will be flat in 2013 as conservation programs and time of use pricing temper demand. Ontario's remaining coal power stations will be retired by the end of 2013. Within the next decade, Ontario's aging nuclear units will require significant investments to extend their lives or will otherwise face retirement, which may provide development opportunities for us in the future.

U.S. Power

In New England, average power demand fell one per cent this year partly due to warm winter weather and there was a net increase of 240 MW of power supply (approximately 400 MW of new power supply was added and 160 MW retired). These supply/demand conditions, combined with low natural gas prices, resulted in a reduction in the average New England ISO power price to US$36/MWh in 2012 from US$47/MWh in

2011. The New England ISO forecasts growth in the demand for power of about one per cent per year in the coming years, based on modest economic growth.

Average power demand in New York fell one per cent in 2012 because of the economic situation, warm winter weather and the loss of demand associated with Superstorm Sandy. There was also a net reduction of 100 MW in power supply (approximately 500 MW of new power supply was added and 600 MW was retired). This supply/demand environment, combined with low natural gas prices, reduced the average New York ISO power price for New York City to US$39/MWh in 2012, from about US$51/MWh in 2011. The New York ISO forecasts power demand will grow one per cent per year over the next decade, based on modest growth in the population and the economy.

Capital expenditures

We spent a total of $24 million in 2012, and expect to spend $130 million on capital expenditures in Energy in 2013. We fund capital expenditures through existing cash flows and access to capital markets. See page 63 for further discussion on liquidity risk.

Equity investments and acquisitions

In 2012, we also invested $0.7 billion in Bruce Power for capital projects which included the restart of Units 1 and 2 and the West Shift Plus life extension outage on Unit 3 as well as $0.2 billion for the acquisition of the remaining 40 per cent interest in CrossAlta. We expect to spend approximately $0.3 billion on the acquisition of Ontario solar assets and Bruce Power investments in 2013.

UNDERSTANDING THE ENERGY BUSINESS

Our Energy business is made up of three groups:

- Canadian Power
- U.S. Power
- Natural Gas Storage

Energy comparable EBIT contribution by group, excluding business development expenses

Year ended December 31, 2012

Power generation capacity contribution by group

Year ended December 31, 2012

Canadian Power

Western Power

We own or have the rights to approximately 2,600 MW of power supply in Alberta and Arizona, through three long-term PPAs, five natural gas-fired cogeneration facilities, and through Coolidge, a simple-cycle, natural gas peaking facility in Arizona.

Power purchased under long-term contracts is as follows:

	Type of contract	With	Expires
Sheerness PPA	Power purchased under a 20-year PPA	ATCO Power and TransAlta Utilities Corporation	2020
Sundance A PPA	Power purchased under a 20-year PPA	TransAlta Utilities Corporation	2017
Sundance B PPA	Power purchased under a 20-year PPA (own 50% through the ASTC Partnership)	TransAlta Utilities Corporation	2020

Power sold under long-term contracts is as follows:

	Type of contract	With	Expires
Coolidge	Power sold under a 20-year PPA	Salt River Project Agricultural Improvements & Power District	2031

Earnings in the Western Power business are maximized by maintaining and optimizing the operations of our power plants, and through various marketing activities.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability, and is not a function of market price.

The marketing function is critical for optimizing returns and managing risk through direct sales to medium and large industrial and commercial companies and other market participants. Our marketing group sells power sourced through the PPAs, markets uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available.

A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

Eastern Power

We own or are developing approximately 3,000 MW of power generation capacity in eastern Canada. All of the power produced by these assets is sold under contract. Disciplined maintenance of plant operations is critical to the results of our eastern power assets, where earnings are based on plant availability and performance.

Assets currently operating under long-term contracts are as follows:

	Type of contract	With	Expires
Bécancour[1]	20-year PPA Steam sold to an industrial customer.	Hydro-Québec	2026
Cartier Wind	20-year PPA	Hydro-Québec	2032
Grandview	20-year tolling agreement to buy 100 per cent of heat and electricity output	Irving Oil	2025
Halton Hills	20-year Clean Energy Supply contract	OPA	2030
Portlands Energy	20-year Clean Energy Supply contract	OPA	2029

1
Power generation has been suspended since 2008.

Assets currently in development are as follows:

	Type of contract	With	Expires
Ontario Solar	20-year Feed-in Tariff (FIT) contracts	OPA	20 years from in-service date
Napanee	20-year Clean Energy Supply contract	OPA	20 years from in-service date

Western and Eastern Power results[1,2]
Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 12 for more information.

year ended December 31 (millions of $)	**2012**	**2011**	**2010**
Revenue			
Western power[1]	**640**	822	598
Eastern power[2]	**415**	391	243
Other[3]	**91**	69	83
	1,146	1,282	924
Income from equity investments[4]	**68**	117	74
Commodity purchases resold			
Western power	**(281)**	(368)	(363)
Other[5]	**(5)**	(9)	(26)
	(286)	(377)	(389)
Plant operating costs and other	**(218)**	(242)	(185)
Sundance A PPA arbitration decision[6]	**(30)**	-	-
General, administrative and support costs	**(48)**	(43)	(38)

Comparable EBITDA	**632**	737	386
Depreciation and amortization[7]	**(152)**	(141)	(114)
Comparable EBIT	**480**	596	272

1
Includes Coolidge starting in May 2011.

2
Includes Cartier phase two of Gros-Morne starting in November 2012, phase one of Gros-Morne starting in November 2011, and Montagne- Sèche starting in November 2011; Halton Hills starting in September 2010.

3
Includes sale of excess natural gas purchased for generation and sales of thermal carbon black.

4
Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy.

5
Includes the cost of excess natural gas not used in operations.

6
See *Significant events* for more information about the Sundance A PPA arbitration decision.

7
Does not include depreciation and amortization of equity investments.

Sales volumes and plant availability[1,2]
Includes our share of volumes from our equity investments.

year ended December 31	2012	2011	2010
Sales volumes (GWh)			
Supply			
Generation			
Western Power[1]	**2,691**	2,606	2,373
Eastern Power[2]	**4,384**	3,714	2,359
Purchased			
Sundance A & B and Sheerness PPAs[3]	**6,906**	7,909	10,785
Other purchases	**46**	248	314
	14,027	14,477	15,831
Sales			
Contracted			
Western Power[1]	**8,240**	8,381	10,096
Eastern Power[2]	**4,384**	3,714	2,375
Spot			
Western Power	**1,403**	2,382	3,360
	14,027	14,477	15,831

Plant availability[4]
Western Power[1,5]