Management's discussion and analysis

February 19, 2014

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the year ended December 31, 2013.

This MD&A should be read with our accompanying December 31, 2013 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

Contents

About this document

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

Abbreviations and acronyms that are not defined in the document are defined in the glossary on page 96.

All information is as of February 19, 2014 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 and future financing options available to us
- 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 impact of regulatory 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 accounting changes, 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 financings 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 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
- costs for labour, equipment and materials
- access to capital markets
- interest and foreign exchange rates
- weather
- cyber security
- 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).

As actual results could vary significantly from the forward-looking information, 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 165 for other consolidated financial information on TransCanada for the last three years.

You can also find more information about TransCanada 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, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and oil pipelines, power generation and natural gas storage facilities.

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 $54 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.

Natural Gas Pipelines

Canadian Pipelines

1 NGTL System
2 Canadian Mainline
3 Foothills
4 Trans Québec & Maritimes (TQM)

U.S. Pipelines

5 ANR Pipeline
5a ANR Regulated Natural Gas Storage
6 Bison
7 Gas Transmission Northwest (GTN)
8 Great Lakes
9 Iroquois
10 North Baja
11 Northern Border
12 Portland
13 Tuscarora

Mexican Pipelines

14 Guadalajara
15 Tamazunchale

Under Construction

16 Mazatlan Pipeline
17 Tamazunchale Pipeline Extension
18 Topolobampo Pipeline

In Development

19 Alaska LNG Pipeline
20 Coastal GasLink
21 Prince Rupert Gas Transmission
22 North Montney Mainline

Oil Pipelines

Canadian / U.S. Pipelines

23 Keystone Pipeline System

Under Construction

24 Cushing Marketlink Receipt Facility
25 Houston Lateral and Terminal
26 Keystone Hardisty Terminal

In Development

27 Bakken Marketlink Receipt Facility
28 Grand Rapids Pipeline
29 Keystone XL
30 Northern Courier Pipeline
31 Heartland Pipeline
32 TC Terminals
33 Energy East Pipeline

Energy

Canadian - Western Power

34 Bear Creek
35 Cancarb
36 Carseland
37 Coolidge[1]
38 Mackay River
39 Redwater
40 Sheerness PPA
41 Sundance A PPA
41 Sundance B PPA

Canadian - Eastern Power

42 Bécancour
43 Cartier Wind
44 Grandview
45 Halton Hills
46 Portlands Energy
47 Ontario Solar (4 Facilities)

Bruce Power

48 Bruce A
48 Bruce B

U.S. Power

49 Kibby Wind
50 Ocean State Power
51 Ravenswood
52 TC Hydro

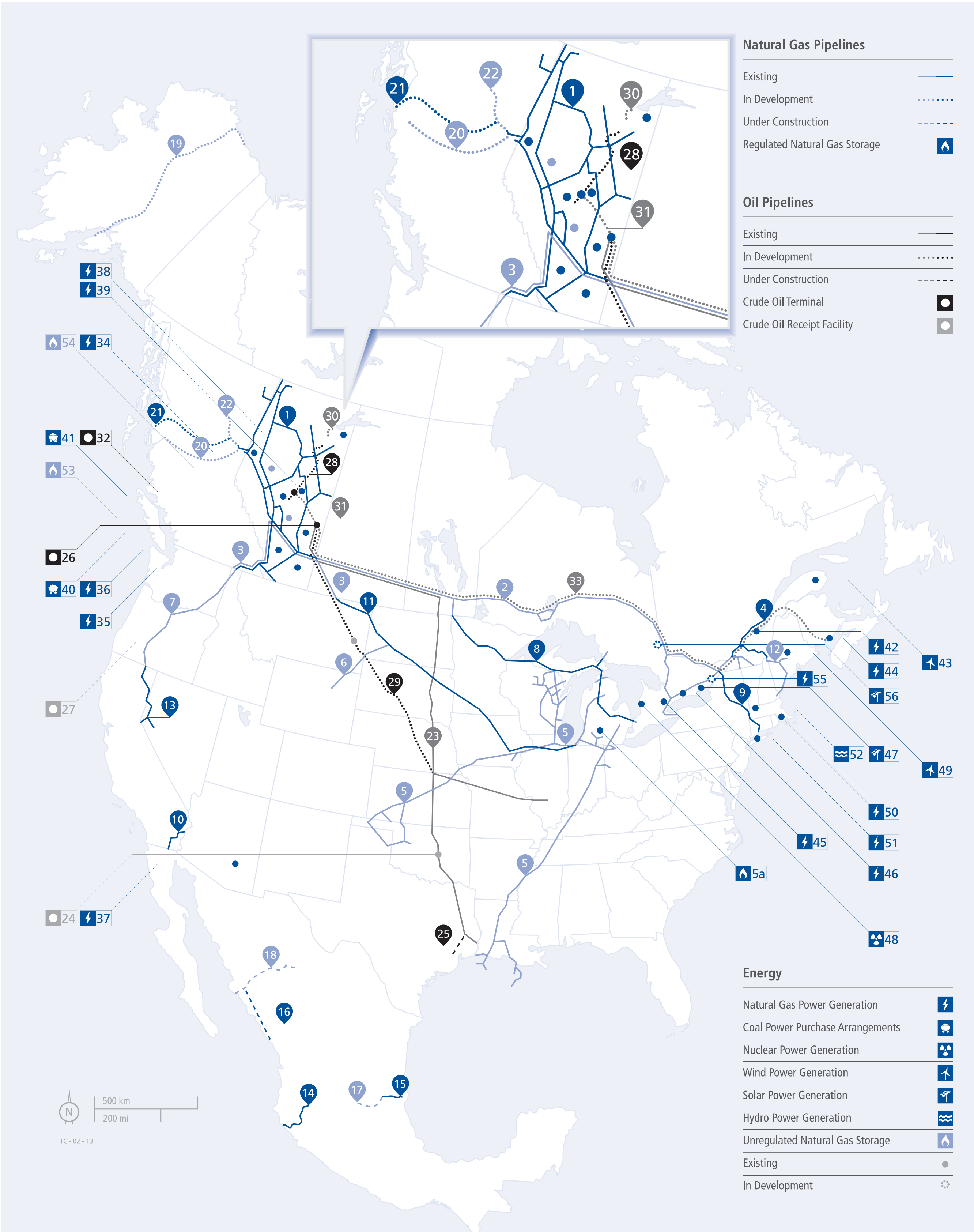
Unregulated Natural Gas Storage

53 CrossAlta
54 Edson

In Development

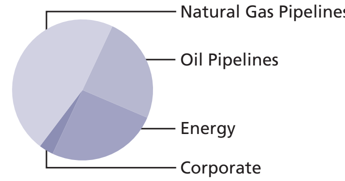
55 Napanee
56 Ontario Solar (5 Facilities)

[1] Located in Arizona, results reported in Canadian - Western Power

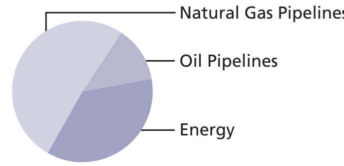


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
Oil Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
Crude Oil Receipt Facility
Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
Existing
In Development
500 km
200 mi
N
TC - 02 - 13

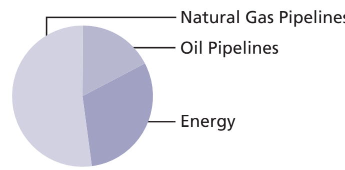
at December 31 (millions of $)	2013	2012	per cent change
Total assets			
Natural Gas Pipelines	**25,165**	23,210	8%
Oil Pipelines	**13,253**	10,485	26%
Energy	**13,747**	13,157	4%
Corporate	**1,733**	1,544	12%
	53,898	48,396	11%



year ended December 31 (millions of $)	2013	2012	per cent change
Total revenue			
Natural Gas Pipelines	**4,497**	4,264	5%
Oil Pipelines	**1,124**	1,039	8%
Energy	**3,176**	2,704	17%
	8,797	8,007	10%

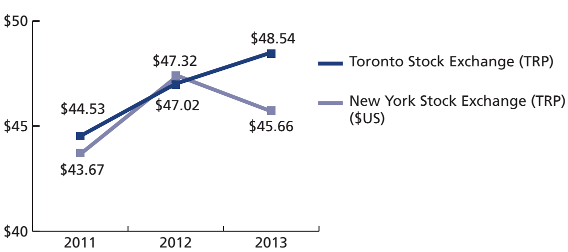


year ended December 31 (millions of $)	2013	2012	per cent change
Comparable EBIT[1]			
Natural Gas Pipelines	**1,839**	1,808	2%
Oil Pipelines	**603**	553	9%
Energy	**1,069**	620	72%
Corporate	**(124)**	(111)	12%
	3,387	2,870	18%



1 Comparable EBIT is a non-GAAP measure – see page 15 for details.

Share price of our common shares
at December 31



Common shares outstanding – average

(millions)	
2013	707
2012	705
2011	702

as at February 14, 2014 Common shares	Issued and outstanding
	707 million

Preferred shares	Issued and outstanding	Convertible to
Series 1	22 million	22 million Series 2 preferred shares
Series 3	14 million	14 million Series 4 preferred shares
Series 5	14 million	14 million Series 6 preferred shares
Series 7	24 million	24 million Series 8 preferred shares
Series 9	18 million	18 million Series 10 preferred shares

Options to buy common shares	Outstanding	Exercisable
	7 million	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.

TransCanada'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, long-term power sale agreements and shorter-term power sales to wholesale and load customers are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

Our strategy at a glance

- We are developing high quality, long-life projects under our current $38 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 returns to shareholders.
- As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully build and integrate new energy and pipeline facilities.
- Our growing investment in natural gas, nuclear, wind, hydro and solar generating facilities demonstrates our commitment to clean, sustainable energy.

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 assess opportunities to acquire and develop energy infrastructure that complements our existing portfolio and provides access to attractive supply and market regions.
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns 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 us our competitive edge.

- Strong leadership: scale, presence, operating capabilities, strategy development; expertise in regulatory, legal, commercial 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 sizable 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.

$38 billion capital program

We are developing quality projects under our long-term $38 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties and are expected to generate significant growth in earnings and cashflow.

Our $38 billion capital program is comprised of $12 billion of small to medium-sized projects and $26 billion of large scale projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

at December 31, 2013 (billions of $)	**Expected In-Service Date**	**Estimated Project Cost**	**Amount Spent**
Small to medium-sized projects			
Gulf Coast Project[1]	January 2014	US 2.6	US 2.3
Ontario Solar	2014	0.5	0.2
Tamazunchale Extension	2014	US 0.5	US 0.4
Houston Lateral and Terminal	2015	US 0.4	US 0.1
Heartland and TC Terminals	2016	0.9	-
Keystone Hardisty Terminal	2016	0.3	0.1
Topolobampo	2016	US 1.0	US 0.4
Mazatlan	2016	US 0.4	US 0.1
Grand Rapids[2]	2015-2017	1.5	0.1
Northern Courier	2017	0.8	0.1
NGTL System	2014-2018	2.0	0.2
Napanee	2017 or 2018	1.0	-
		11.9	4.0
Large scale projects[3]			
Keystone XL[4]	Approximately 2 years from date permit received	US 5.4	US 2.2
Energy East[5]	2018	12.0	0.2
Prince Rupert Gas Transmission	2018	5.0	0.1
Coastal GasLink	2018+	4.0	0.1
		26.4	2.6
		38.3	6.6

1 Commercial in-service date of January 22, 2014.
2 Represents our 50 per cent share.
3 Subject to cost adjustments due to market conditions, route refinement, permitting conditions and scheduling.
4 Estimated project cost will increase depending on the timing of the Presidential permit.
5 Excludes transfer of Canadian Mainline gas assets.

2013 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under 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.

Highlights

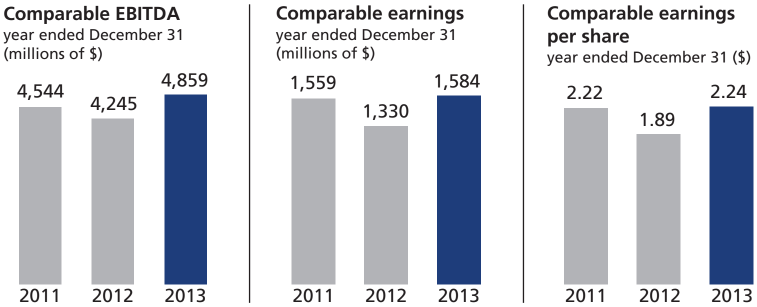
Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share and funds generated from operations are all non-GAAP measures. See page 15 for more information about the non-GAAP measures we use and a reconciliation to their GAAP equivalents.

year ended December 31 (millions of $, except per share amounts)	**2013**	**2012**	**2011**
Revenue	**8,797**	8,007	7,839
Comparable EBITDA	**4,859**	4,245	4,544
Net income attributable to common shares	**1,712**	1,299	1,526
per common share – basic and diluted	**$2.42**	$1.84	$2.17
Comparable earnings	**1,584**	1,330	1,559
per common share	**$2.24**	$1.89	$2.22
Operating cash flow			
Funds generated from operations	**4,000**	3,284	3,451
(Increase)/decrease in working capital	**(326)**	287	235
Net cash provided by operations	**3,674**	3,571	3,686
Investing activities			
Capital expenditures	**4,461**	2,595	2,513
Equity investments	**163**	652	633
Acquisitions, net of cash acquired	**216**	214	-
Balance sheet			
Total assets	**53,898**	48,396	47,338
Long-term debt	**22,865**	18,913	18,659
Junior subordinated notes	**1,063**	994	1,016
Preferred shares	**1,813**	1,224	1,224
Common shareholders' equity	**16,712**	15,687	15,570
Dividends declared			
per common share	**$1.84**	$1.76	$1.68
per Series 1 preferred share	**$1.15**	$1.15	$1.15
per Series 3 preferred share	**$1.00**	$1.00	$1.00
per Series 5 preferred share	**$1.10**	$1.10	$1.10
per Series 7 preferred share[1]	**$0.91**	-	-

1 Issued March 4, 2013.

Comparable earnings and net income

Comparable earnings



Comparable earnings in 2013 were $254 million higher than in 2012, an increase of $0.35 per share.

The increase in comparable earnings was the result of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4
- higher earnings from the Canadian Mainline reflecting the higher rate of return on common equity (ROE) of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the National Energy Board's (NEB) 2013 decision on the Canadian Restructuring Proposal (the NEB decision)
- higher earnings from U.S. Power because of higher capacity prices in New York and higher realized power prices
- higher earnings from the NGTL System reflecting a higher investment base and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013
- higher earnings from the Keystone Pipeline System primarily due to higher volumes
- higher earnings from Western Power because of higher purchased volumes under the power purchase arrangements (PPA).

These increases were partly offset by lower contributions from U.S. natural gas pipelines because of lower earnings at ANR and Great Lakes.

Comparable earnings in 2012 were $229 million lower than 2011, a decrease of $0.33 per share.

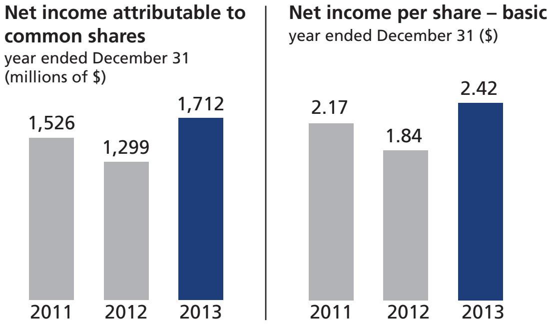
The decrease in comparable earnings was the result of:

- 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
- 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
- higher comparable interest expense, mainly because of new debt issuances in 2011 and 2012.

These decreases were partially offset by:

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

Net income attributable to common shares



Net income attributable to common shares in 2013 was $1,712 million, a year-over-year increase of $413 million (2012 – $1,299 million; 2011 – $1,526 million).

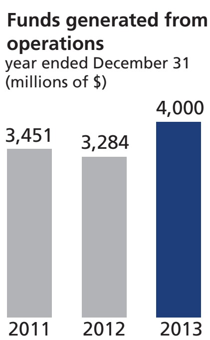
Net income attributable to common shares includes comparable earnings discussed above as well as other specific items which are excluded from comparable earnings. See page 15 for explanation of specific items in non-GAAP measures. The following specific items were recognized in net income in 2011 to 2013:

- $84 million of net income recorded in 2013 related to 2012 from the NEB decision
- $25 million favourable tax adjustment in 2013 due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax
- $15 million after-tax charge ($20 million pre-tax) in 2012 related to the Sundance A PPA arbitration decision. This charge was recorded in second quarter 2012 but related to amounts originally recorded in fourth quarter 2011
- the impact of certain risk management activities each year.

Cash flow

Funds generated from operations

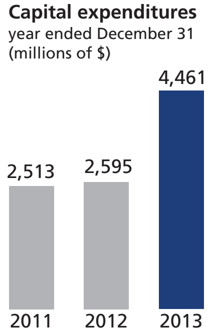
Funds generated from operations were 22 per cent higher this year compared to 2012 primarily for the same reasons comparable earnings were higher, as described above.



Funds used in investing

Capital expenditures

We invested $4.5 billion in capital projects this year as part of our ongoing capital program compared to $6.4 billion we expected to spend in 2013 primarily because of the delay in Keystone XL permitting. Our capital 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 that are expected to generate stable, predictable earnings and cash flow for years to come.



Capital expenditures

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Natural Gas Pipelines	**1,776**	1,389	917
Oil Pipelines	**2,483**	1,145	1,204
Energy	**152**	24	384
Corporate	**50**	37	8
	4,461	2,595	2,513

Equity investments and acquisitions

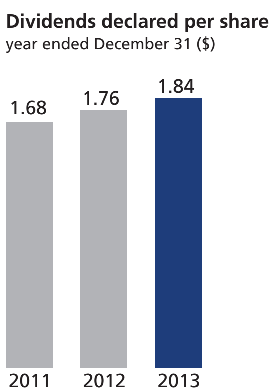
In 2013, we invested $0.2 billion in our equity investments. We also spent $0.2 billion on the acquisition of four solar facilities from Canadian Solar Solutions Inc.

Balance sheet

We maintained a strong balance sheet while growing our total assets by $6.6 billion since 2011. At December 31, 2013, common equity represented 40 per cent (42 per cent in 2012) of our capital structure. See page 68 for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by four per cent to $0.48 per share for the quarter ending March 31, 2014 which equates to an annual dividend of $1.92 per share. This is the 14th consecutive year we have increased the dividend on our common shares representing a compound annual growth rate of seven per cent since 2000.



Dividend reinvestment plan

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

Before April 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 annual dividends paid on common shares since 2011 is, in part, the result of this change combined with the impact of increases in the annualized dividend rate between 2011 and 2013 from $1.68 to $1.84 per share.

Quarterly dividend on our common shares

$0.48 per share (for the quarter ending March 31, 2014)

Annual dividends on our preferred shares

Series 1 $1.15

Series 3 $1.00

Series 5 $1.10

Series 7 $1.00

Series 9 $1.06

Cash dividends

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Common shares	**1,285**	1,226	961
Preferred shares	**71**	55	55

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 2014 to be higher than 2013, mainly due to the net effect of the following:

- Gulf Coast project achieving commercial in service in January 2014
- Tamazunchale Pipeline Extension which is expected to be placed in service in second quarter 2014
- expected higher realized capacity and commodity prices in New York and New England
- full year of earnings from four solar facilities acquired in 2013 as well as the additional facilities expected to be acquired in 2014
- anticipated lower Alberta power prices and lower gas storage spreads
- no earnings from Cancarb Limited and its related power generation facility after the sale which is expected to close late in first quarter 2014
- higher operating, maintenance and administration (OM&A) costs related to new growth projects.

Results from our U.S. businesses are subject to fluctuations in foreign exchange rates. These fluctuations are largely offset by our hedging activities which are recorded in our Corporate segment.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segment in 2014 will be affected by regulatory decisions and the timing of those decisions. Earnings will also be affected by market conditions, which drive the level of demand and the rates we 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.

For 2014, the Canadian Mainline will continue to operate under the direction of the NEB decision which included an ROE of 11.50 per cent. We also expect the NGTL System's investment base to continue to grow as new natural gas supply in northeastern B.C. and western Alberta continues to be developed which will have a positive impact on earnings in 2014.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. ANR and Great Lakes have had more commercial exposure from transportation and storage contract renewals which resulted in reduced earnings in 2012 and 2013 as transportation and storage values fell to historically low levels. ANR and GLGT are examining commercial, regulatory and operational changes to optimize their position to benefit from positive developments in supply fundamentals, particularly in the Utica/Marcellus shale areas, combined with continued growth in end use markets for natural gas. In addition, significant effort to reduce costs for our U.S. pipelines operations are underway and expected to help with the near term revenue challenges. Overall in 2014, we expect earnings from our U.S. Pipelines to be consistent with 2013.

Earnings from our Mexican pipelines are expected to be higher in 2014 compared to 2013 as a result of the Tamazunchale Pipeline Extension being placed in service in second quarter 2014. Earnings for our current operating assets are expected to be consistent with 2013 due to the long-term nature of the contracts for these pipeline systems.

Oil Pipelines

Oil Pipelines principally generate earnings by providing pipeline capacity to shippers 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 which provides opportunities to generate incremental earnings.

The Gulf Coast project, an extension of the Keystone Pipeline System achieved commercial in-service in January 2014 and is expected to have a positive impact on the Oil Pipelines segment earnings in 2014. Although the majority of the capacity on this extension is contracted, the actual results for 2014 will be impacted by the level and pricing of spot volumes shipped each month, which is a function of available capacity, market conditions and competitive transportation options.

Energy

The higher level of power plant outages and other supply challenges that contributed to higher than expected prices and volatility within the Alberta power market in 2013 are not anticipated to continue in 2014. The sale of Cancarb Limited and its related power generation facility, which is expected to close in late first quarter 2014, as well as lower forecasted prices are expected to result in lower earnings in Western Power in 2014.

Eastern Power earnings in 2014 are expected to be relatively consistent with 2013 with earnings from a full year of service for four solar facilities offset by lower contributions from Bécancour.

Bruce Power equity income is expected to be consistent with 2013 earnings.

U.S. Power earnings are expected to be higher in 2014 due to an increase in realized capacity prices and commodity prices partially offset by lower power marketing contribution. Commodity prices for both power and natural gas are forecasted to be higher in 2014. As well, increased competition will continue to put downward pressure on retail and wholesale marketing margins and volumes in the U.S. Power segment.

Lower summer-to-winter natural gas spreads are expected to result in lower earnings from Natural Gas Storage.

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 expect to spend approximately $5 billion in 2014 on new and existing capital projects, excluding Keystone XL. The amount and timing of capital spending on Keystone XL will be dependent on the decision by the U.S. Department of State (DOS) to issue a Presidential Permit. The 2014 expected capital spending relates to the NGTL System expansion, Mexican pipelines and new growth pipeline projects including Heartland, Northern Courier and Grand Rapids.

NON-GAAP MEASURES

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable depreciation and amortization
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by 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 tax, 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 9 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. These comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Comparable measure	Original measure
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable EBITDA	EBITDA
comparable EBIT	EBIT
comparable depreciation and amortization	depreciation and amortization
comparable interest expense	interest expense
comparable interest income and other	interest income and other
comparable income tax expense	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
- impact of regulatory or arbitration decisions relating to prior year earnings
- 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)	2013	2012	2011
EBITDA	**4,958**	4,224	4,495
Non-comparable risk management activities affecting EBITDA	**(44)**	21	49
NEB decision – 2012	**(55)**	-	-
Comparable EBITDA	**4,859**	4,245	4,544
Comparable depreciation and amortization	**(1,472)**	(1,375)	(1,328)
Comparable EBIT	**3,387**	2,870	3,216
Other income statement items			
Comparable interest expense	**(984)**	(976)	(939)
Comparable interest income and other	**42**	86	60
Comparable income tax	**(662)**	(477)	(594)
Net income attributable to non-controlling interests	**(125)**	(118)	(129)
Preferred share dividends	**(74)**	(55)	(55)
Comparable earnings	**1,584**	1,330	1,559
Specific items (net of tax):			
NEB decision – 2012	**84**	-	-
Part VI.I income tax adjustment	**25**	-	-
Sundance A PPA arbitration decision – 2011	**-**	(15)	-
Risk management activities[1]	**19**	(16)	(33)
Net income attributable to common shares	**1,712**	1,299	1,526
Comparable depreciation and amortization	**(1,472)**	(1,375)	(1,328)
Specific item:			
NEB decision – 2012	**(13)**	-	-
Depreciation and amortization	**(1,485)**	(1,375)	(1,328)
Comparable interest expense	**(984)**	(976)	(939)
Specific items:			
NEB decision – 2012	**(1)**	-	-
Risk management activities[1]	**-**	-	2
Interest expense	**(985)**	(976)	(937)
Comparable interest income and other	**42**	86	60
Specific items:			
NEB decision – 2012	**1**	-	-
Risk management activities[1]	**(9)**	(1)	(5)
Interest income and other	**34**	85	55

year ended December 31 (millions of $, except per share amounts)	2013	2012	2011
Comparable income tax expense	**(662)**	(477)	(594)
Specific items:			
NEB decision – 2012	**42**	-	-
Part VI.I income tax adjustment	**25**	-	-
Sundance A PPA arbitration decision – 2011	**-**	5	-
Risk management activities[1]	**(16)**	6	19
Income tax expense	**(611)**	(466)	(575)
Comparable earnings per common share	**$2.24**	$1.89	$2.22
Specific items (net of tax):			
NEB decision – 2012	**0.12**	-	-
Part VI.I Income tax adjustment	**0.04**	-	-
Sundance A PPA arbitration decision – 2011	**-**	(0.02)	-
Risk management activities[1]	**0.02**	(0.03)	(0.05)
Net income per common share	**$2.42**	$1.84	$2.17

1

year ended December 31 (millions of $)	2013	2012	2011
Canadian Power	**(4)**	4	1
U.S. Power	**50**	(1)	(48)
Natural Gas Storage	**(2)**	(24)	(2)
Interest rates	**-**	-	2
Foreign exchange	**(9)**	(1)	(5)
Income tax attributable to risk management activities	**(16)**	6	19
Total gains/(losses) from risk management activities	**19**	(16)	(33)

Comparable EBITDA and comparable EBIT by business segment

year ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	**2,852**	**752**	**1,363**	**(108)**	**4,859**
Comparable depreciation and amortization	**(1,013)**	**(149)**	**(294)**	**(16)**	**(1,472)**
Comparable EBIT	**1,839**	**603**	**1,069**	**(124)**	**3,387**

year ended December 31, 2012 (millions of $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,741	698	903	(97)	4,245
Comparable 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 $)	Natural Gas Pipelines	Oil Pipelines	Energy	Corporate	Total
Comparable EBITDA	2,875	587	1,168	(86)	4,544
Comparable depreciation and amortization	(923)	(130)	(261)	(14)	(1,328)
Comparable EBIT	1,952	457	907	(100)	3,216

Natural Gas Pipelines

Our natural gas pipeline network transports natural gas to local distribution companies, power generation facilities and other businesses across Canada, the U.S. and Mexico. We serve more than 80 per cent of the Canadian demand and approximately 15 per cent of the U.S. 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)
- 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.

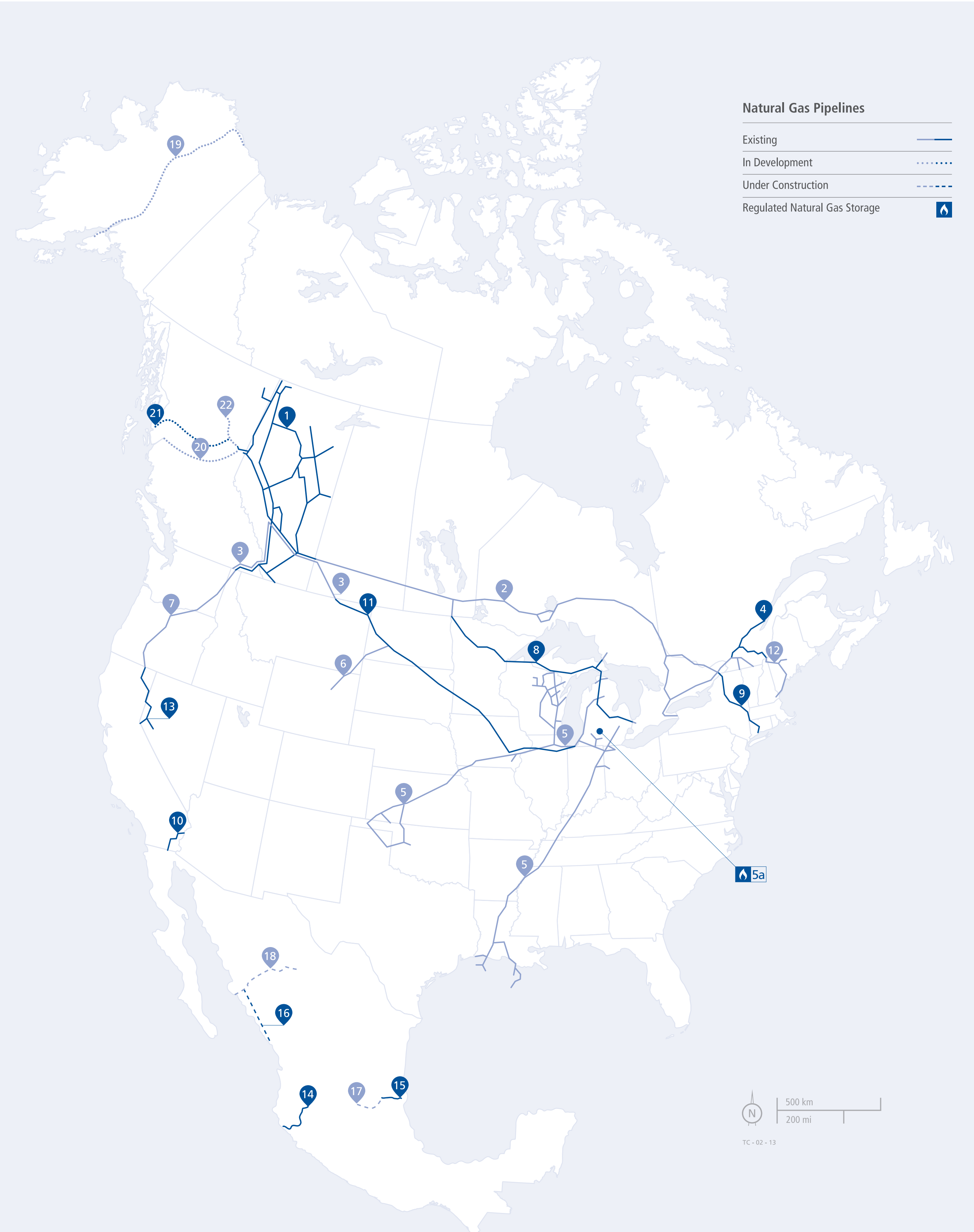
Strategy at a glance

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 from the west coast of Canada and additional pipeline developments within Mexico
- connections to emerging Canadian and U.S. shale gas and other supplies
- connections to new and growing markets

all of which play a critical role in meeting the increasing demand for natural gas in North America.


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
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We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		length	description	effective ownership
	Canadian pipelines			
1	NGTL System	24,522 km (15,237 miles)	Gathers and transports natural gas within Alberta and northeastern B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines	100%
2	Canadian Mainline	14,114 km (8,770 miles)	Transports natural gas from the Alberta/Saskatchewan border to serve eastern Canada and the U.S. northeast markets	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 Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
	ANR			
5	Pipeline	16,121 km (10,017 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 to the Gulf Coast region as well as Wisconsin, Michigan, Illinois, Indiana and Ohio. Connects with Great Lakes	100%
5a	Storage	250 Bcf	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 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TC PipeLines, LP	50.2%
7	Gas Transmission Northwest (GTN)	2,178 km (1,353 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 50.2 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.9 per cent interest in TC PipeLines, LP	50.2%
8	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada, and the U.S. upper Midwest. We effectively own 67 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.9 per cent interest in TC PipeLines, LP	67%
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 Arizona and California, and connects with another third-party system on the California/Mexico border. We effectively own 28.9 per cent of the system through our interest in TC PipeLines, LP	28.9%
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 14.5 per cent of the system through our 28.9 per cent interest in TC PipeLines, LP	14.5%
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 Nevada, and delivers gas in northeastern California and northwestern Nevada. We effectively own 28.9 per cent of the system through our interest in TC PipeLines, LP	28.9%
Mexican pipelines			
14 Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
15 Tamazunchale	130 km (81 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi	100%
Under construction			
16 Mazatlan Pipeline	413 km (257 miles)	To deliver natural gas from El Oro to Mazatlan, Sinaloa in Mexico. Will connect to the Topolobampo Pipeline at El Oro	100%
17 Tamazunchale Pipeline Extension	235 km (146 miles)	To extend existing terminus of the Tamazunchale Pipeline to deliver natural gas to power generating facilities in El Sauz, Queretaro and other parts of central Mexico	100%
18 Topolobampo Pipeline	530 km (329 miles)	To deliver natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico	100%
In development			
19 Alaska LNG Pipeline	1,448 km* (900 miles)	To transport natural gas from Prudhoe Bay to LNG facilities in Nikiski, Alaska	
20 Coastal GasLink	650 km* (404 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
21 Prince Rupert Gas Transmission	750 km* (466 miles)	To deliver natural gas from the North Montney gas producing region at a NGTL interconnect near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
22 North Montney Mainline	306 km* (190 miles)	To deliver natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline	100%

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

RESULTS

Natural Gas Pipelines results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Canadian Pipelines			
Canadian Mainline	**1,121**	994	1,058
NGTL System	**846**	749	742
Foothills	**114**	120	127
Other Canadian (TQM[1], Ventures LP)	**26**	29	34
Canadian Pipelines – comparable EBITDA	**2,107**	1,892	1,961
Comparable depreciation and amortization	**(790)**	(715)	(711)
Canadian Pipelines – comparable EBIT	**1,317**	1,177	1,250
U.S. and International Pipelines (in US$)			
ANR	**188**	254	306
GTN[2]	**76**	112	131
Great Lakes[3]	**34**	62	101
TC PipeLines, LP[1,4]	**72**	74	85
Other U.S. pipelines (Iroquois[1], Bison[2], Portland[5])	**107**	111	111
International (Gas Pacifico/INNERGY[1], Guadalajara[6], Tamazunchale, TransGas[1])	**106**	112	77
General, administrative and support costs	**(10)**	(8)	(9)
Non-controlling interests[7]	**186**	161	173
U.S. and International Pipelines – comparable EBITDA	**759**	878	975
Comparable depreciation and amortization	**(217)**	(218)	(214)
U.S. and International Pipelines – comparable EBIT	**542**	660	761
Foreign exchange impact	**15**	-	(7)
U.S. and International Pipelines – comparable EBIT (Cdn$)	**557**	660	754
Business Development comparable EBITDA and comparable EBIT	**(35)**	(29)	(52)
Natural Gas Pipelines – comparable EBIT	**1,839**	1,808	1,952
Summary			
Natural Gas Pipelines – comparable EBITDA	**2,852**	2,741	2,875
Comparable depreciation and amortization	**(1,013)**	(933)	(923)
Natural Gas Pipelines – comparable EBIT	**1,839**	1,808	1,952

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments.
2 Effective July 1, 2013, reflects our direct ownership interest of 30 per cent. Prior to that our direct ownership interest was 75 per cent effective May 2011 and 100 per cent prior to that date.
3 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TC PipeLines, LP.

4 Effective May 22, 2013, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent. On July 1, 2013, we sold 45 per cent of GTN and Bison to TC PipeLines, LP. The following table shows our ownership interest in TC PipeLines, LP and our ownership of GTN, Bison, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	July 1, 2013	May 22, 2013	May 3, 2011	January 1, 2011
TC PipeLines, LP	28.9	28.9	33.3	38.2
Effective ownership through TC PipeLines, LP:				
GTN/Bison	20.2	7.2	8.3	-
Great Lakes	13.4	13.4	15.5	17.7

5 Represents our 61.7 per cent ownership interest.
6 Included as of June 2011.
7 Comparable EBITDA for the portions of TC PipeLines, LP and Portland we do not own.

Canadian Pipelines

year ended December 31 (millions of $)	2013	2012	2011
Net income			
Canadian Mainline – net income	**361**	187	246
Canadian Mainline – comparable earnings	**277**	187	246
NGTL System	**243**	208	200
Average investment base			
Canadian Mainline	**5,841**	5,737	6,179
NGTL System	**5,938**	5,501	5,074

Comparable EBITDA and net income for our rate-regulated Canadian Pipelines are primarily affected by our approved 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 have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

Canadian Mainline's comparable earnings this year increased by $90 million compared to 2012 because of the impact of the NEB decision. Among other items, the NEB decision approved an ROE of 11.50 per cent on 40 per cent deemed common equity for the years 2012 through 2017 compared to the last approved ROE of 8.08 per cent on 40 per cent deemed common equity that was used to record earnings in 2012. The NEB decision also approved an incentive mechanism based on total net revenues. The 2013 increase in comparable EBITDA is mainly due to the higher ROE plus incentive earnings. Net income of $361 million recorded in 2013 included $84 million related to the 2012 impact of the NEB decision, which was excluded from comparable earnings. Net income in 2012 was $59 million lower than 2011 because there were no incentive earnings and the average investment base was lower as annual depreciation outpaced our capital investment.

Net income in 2013 for the NGTL System was $35 million higher than 2012 because of a higher average investment base associated with 2012 and 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. The settlement included an ROE of 10.10 per cent on 40 per cent deemed common equity, compared to an ROE of 9.70 per cent on 40 per cent deemed equity in 2012, and included annual fixed amounts for certain OM&A costs. Net income in 2012 was $8 million higher than 2011, mainly due to a growing investment base, partially offset by lower incentive earnings.

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

U.S. and International Pipelines

EBITDA for our U.S. operations is affected by contracted volume levels, actual 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 level of contracting and the determination of rates driven by the market value of its storage capacity, storage related transportation services, 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$119 million lower in 2013 than 2012. This was due to the net effect of:

- lower transportation and storage revenues at ANR offset by higher incidental commodity sales
- higher OM&A and other costs relating to services provided by other pipelines to ANR
- lower revenue at Great Lakes because of uncontracted capacity
- lower contributions from GTN and Bison due to the reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent, effective July 1, 2013
- higher contributions from Portland due to higher short term revenues.

Comparable EBITDA for the U.S. and International Pipelines was US$97 million lower in 2012 than 2011. This was due to 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 costs at ANR
- incremental earnings from the Guadalajara pipeline which started operations in June 2011.

Comparable depreciation and amortization

Comparable depreciation and amortization was $80 million higher in 2013 than in 2012 mainly because of a higher NGTL System investment base and higher composite depreciation rate in the 2013-2014 Settlement, as well as the impact of the NEB decision. Depreciation and amortization was $10 million higher in 2012 than in 2011 mainly because Bison began operations in January 2011 and Guadalajara began operations in June 2011.

Business development

In 2013, business development expenses were $6 million higher than last year and $23 million lower in 2012 compared to 2011. Both variances are mainly due to a change in scope on the Alaska pipeline project. See page 32 for further discussion on Alaska.

OUTLOOK

Canadian Pipelines

Earnings

Earnings for Canadian Pipelines 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.

For 2014, we expect the Canadian Mainline will continue to operate under the direction of the NEB decision which included an ROE of 11.50 per cent. We expect 2014 earnings to be in line with 2013.

We expect the NGTL System investment base to continue to grow as we connect new natural gas supply in northeastern B.C. and western Alberta and respond to growing demand in the oil sands market in northeast Alberta. We expect the growing investment base to have a positive impact on earnings in 2014.

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 materially 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

U.S. Pipeline 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. Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulator's decisions.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance. ANR and Great Lakes have had more commercial exposure from transportation and storage contract renewals which resulted in reduced earnings in 2012 and 2013 as transportation and storage values were depressed to historically low levels.

ANR and Great Lakes are examining commercial, regulatory and operational changes to optimize their position from positive developments in supply fundamentals, particularly in the Utica/Marcellus shale plays, combined with continued growth in end use markets for natural gas. In addition, significant efforts to reduce costs for our U.S. pipelines operations are underway and are expected to help with the near term revenue challenges. Overall in 2014, we expect earnings from our U.S. Pipelines to be consistent with 2013.

Mexican Pipelines

Overall earnings from our Mexican pipelines in 2014 are expected to be higher than 2013 due to the Tamazunchale Pipeline Extension which is expected to be placed in service in second quarter 2014. The 2014 earnings for our current operating assets are expected to be consistent with 2013 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital expenditures

We spent a total of $1.8 billion in 2013 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $2 billion in 2014 primarily on the NGTL System expansion projects, the Topolobampo and Mazatlan pipelines in Mexico, and the Prince Rupert and Coastal GasLink LNG pipelines. See page 82 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 to end customers such as local distribution companies, power generation facilities, industrial operations and other pipeline interconnects or end-users. The network includes pipelines that are buried underground and transport natural gas under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline and meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the delivery locations.

Regulation of tolls and cost recovery

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

Regulators in Canada, the U.S. and Mexico allow us to recover 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 tolls that provide us a reasonable opportunity to recover them.

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 operator may negotiate lower rates with shippers.

Sometimes we enter into agreements or settlements with our shippers 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, Canadian natural gas pipelines request the NEB to approve the pipeline's cost of service and tolls once a year, and recover or refund the variance between actual and expected revenues and costs in future years. Due to the NEB decision, the Canadian Mainline was required to fix its contracted tolls for five years (2013-2017) and defer certain costs to the end of the five-year period. The Mainline was also given flexibility to price its discretionary or uncontracted services in order to maximize its revenue.

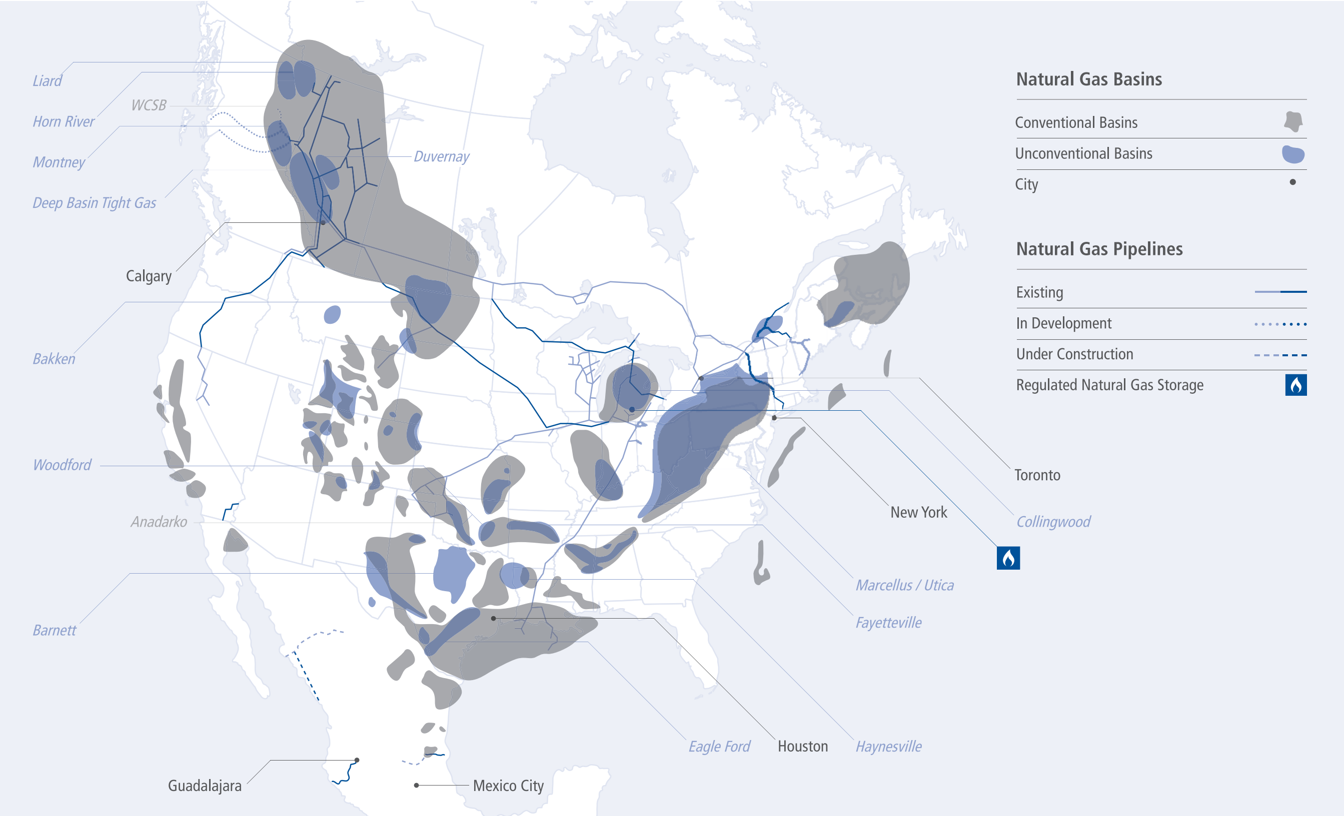
The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected and 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 Mexican pipelines are also regulated and have approved tariffs, services and related rates. However, the contracts underpinning the construction and operation of the facilities in Mexico are long-term negotiated fixed-rate contracts. These rates are only subject to change under specific circumstances such as certain types of force majeure events or changes in law.

Business environment and strategic priorities

The North American natural gas pipeline network has 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 as well as changing demand.

We have a significant pipeline footprint in the WCSB and transport approximately 75 per cent of total WCSB production to markets within and outside of the basin. Our pipelines also source natural gas, to a lesser degree, from the other major basins including the Appalachian (Utica and Marcellus), Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the 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 150 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of almost 780 trillion cubic feet. The total WCSB resource base has recently more than quadrupled with the advent of technology that can economically access unconventional gas areas in the basin. We expect production from the WCSB to increase slightly in 2014 after decreasing every year since 2006. WCSB production is expected to continue to increase over the next several years. 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 2 Bcf/d, to grow to approximately 6 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 areas, 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 demand by 2020. Of the shale areas in the U.S, the Utica, Marcellus, Haynesville, Barnett, Eagle Ford and Fayetteville are the major supply sources.

The supply of natural gas in North America is forecast to increase significantly over the next decade (by approximately 20 Bcf/d or 22 per cent 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 in the U.S. northeast, and the Montney and Horn River 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, have resulted in an increase in exploration and production of liquid-rich hydrocarbon basins. There is often associated gas in these areas (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 existing markets, particularly in the northeast U.S., has led to an increase in the number of supply choices and is changing historical gas pipeline flow patterns, generally from long-haul, long-term firm contracted capacity to shorter-distance, shorter-term contracts. While the Canadian Mainline has also seen this shift following the NEB decision, we have seen a considerable volume of long-haul transportation recontracted through 2014.

While the increase in supply, particularly in northeastern B.C., has created opportunities for us to build and plan new large pipeline infrastructure on the NGTL System to move the natural gas to markets, including proposed LNG exports, the majority of existing Canadian and U.S. pipelines, including ours, have focused on smaller debottlenecking or short pipe connections as part of any new infrastructure development.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which have supported increased demand for natural gas particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands
- exports to Mexico to fuel new power generation facilities.

Natural gas producers are also assessing opportunities 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. Assuming the receipt of all necessary regulatory and other approvals, these facilities are expected to become operational later in 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 levels and locations have resulted in increased competition for transportation services throughout North America. Development technology for shale gas supply basins that are closer to markets historically served has resulted in changes to flow patterns of existing natural gas pipeline infrastructure from long haul to shorter haul distances particularly with the large development of U.S. northeast supply. Along with other pipelines, we are restructuring our tolls and service offerings to capture this growing northeast supply and North American demand.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, and connecting 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 continued to be a focal point in 2013 following the receipt and implementation of the NEB decision. Following the NEB decision, we reached an LDC Settlement that addresses issues associated with the NEB decision. The LDC Settlement reflects our focus on developing a framework that balances the needs of our shippers while at the same time ensuring a reasonable opportunity to recover the capital from our existing facilities and any new facilities required to serve existing and new markets.

The NGTL 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 NGTL 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 NGTL System is well positioned to connect WCSB supply to meet expected demand for LNG exports on the B.C. coastline. Obtaining the necessary regulatory approvals to extend and expand the NGTL System into northeast B.C. to connect the Montney shale area will be a key focus in 2014.

Our U.S. pipeline assets are positioned well for anticipated connections to growth in supply and markets for the following reasons:

- expected continued growth in gas-fired generation and therefore load on our pipes, including the new proposed Carty lateral on the GTN system to deliver natural gas to a new power plant in Oregon
- growth in industrial load in response to robust levels of natural gas supply, including connections to the ANR System to serve a new nitrogen fertilizer plant in Iowa
- Utica/Marcellus supply growth and Gulf Coast LNG export development supporting ANR utilization, including the Lebannon Lateral project attracting Utica supply to the ANR system with additional phases of further expansion expected.

Management expects to divest our remaining U.S. natural gas pipeline assets into TC PipeLines, LP over time as a means of funding a portion of our capital growth program.

Our focus in Mexico in 2014 is to complete the Tamazunchale Pipeline Extension project and to advance the construction phase for the Mazatlan and Topolobampo pipelines. We continue to be very interested in the further development of natural gas infrastructure in Mexico and will work to advance future projects that align with the investment profile of our current set of assets.

We continue to assess repurposing opportunities for our existing natural gas pipelines assets, including the possibility of converting existing infrastructure from natural gas to crude oil service. In 2007, we received NEB approval to convert one of our Canadian Mainline gas pipelines to crude oil service for the original Keystone project. Another project, the Energy East Pipeline is planning, subject to regulatory approval, to utilize approximately 3,000 km (1,864 miles) of the Canadian Mainline from the Alberta border to a point in eastern Ontario, southeast of Ottawa. As a result, we are working closely with our shipper community to ensure their firm service needs will continue to be met following the planned conversion.

SIGNIFICANT EVENTS

Canadian Pipelines

In 2013, we completed and placed in service approximately $730 million of pipeline projects to expand and extend the NGTL System and $160 million to expand the Canadian Mainline.

NGTL System

In addition to completing and placing in service new pipeline projects to expand the NGTL System, in 2013 the NEB approved approximately $290 million in additional expansions that are currently in various stages of development or construction but were not in service at the end of 2013.

On November 8, 2013, we filed an application with the NEB to construct and operate the North Montney Project, which is an extension and expansion of the NGTL System to receive and transport natural gas from the

North Montney area of B.C. The estimated capital cost of the project is $1.7 billion and it consists of approximately 300 km (186 miles) of pipeline.

The NEB approved the 2013-2014 NGTL Settlement and final 2013 rates, as filed, in November 2013. We expect the final tolls for 2014 for the NGTL System will be determined on the basis of the NGTL settlement process.

Canadian Mainline

In March 2013, we received the NEB decision on our application to change the business structure and the terms and conditions of service for the Canadian Mainline and implemented the decision on July 1, 2013. The implementation of the NEB decision was a key priority in 2013 and with the ability to price discretionary services at market prices we were able to essentially meet our overall cost of service requirements for 2013.

The NEB decision established a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between our revenues and our cost of service for each year over the five-year term of the decision. The NEB decision also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances is if the TSA balance becomes positive, which occurred in 2013.

The Mainline and the three largest Canadian local distribution companies entered into a settlement (LDC Settlement) which was filed with the NEB for approval in December 2013. The LDC Settlement, if approved, will establish new fixed tolls for 2015 to 2020 and maintain tolls for 2014 at the current rates. The LDC Settlement calculates tolls for 2015 on a base ROE of 10.10 per cent on 40 per cent deemed common equity. It also includes an incentive mechanism that requires a $20 million (after tax) annual contribution by us from 2015 to 2020, which could result in a range of ROE outcomes from 8.70 per cent to 11.50 per cent.

The LDC Settlement will enable the addition of facilities in the Eastern Triangle to serve immediate market demand for supply diversity and market access. The LDC Settlement is intended to provide a market-driven, stable, long-term accommodation of future demand in this region in combination with the anticipated lower demand for transportation on the Prairies Line and the Northern Ontario Line while providing a reasonable opportunity to recover our costs. The LDC Settlement also retains pricing flexibility for discretionary services and implements certain tariff changes and new services as required by the term of the settlement.

The NEB decision remains in effect pending the outcome of the LDC Settlement application.

On January 31, 2014, shippers on the Canadian Mainline elected to renew approximately 2.5 Bcf/d of their contracts through November 2016. This represents a significant amount of volume renewal, especially by Canadian shippers.

U.S. Pipelines

Bison and GTN

In July 2013, we sold an additional 45 per cent interest in each of GTN and Bison to TC PipeLines, LP. for an aggregate purchase price of US$1.05 billion. We continue to hold a 30 per cent direct ownership interest in both pipelines. We also hold 28.9 per cent interest in, and are the General Partner of, TC PipeLines, LP.

ANR Lebanon Lateral Reversal Project

Following a successful binding open season which concluded in October 2013, we have executed firm transportation contracts for 350 million cubic feet per day at maximum tariff rates for 10 years on the ANR Lebanon Lateral Reversal Project, which will entail modifications to existing facilities. The facility modifications are expected to be completed in first quarter 2014. Contracted volumes will increase over the course of 2014 generating incremental earnings. The project will substantially increase our ability to receive gas on ANR's southeast mainline from the Utica/Marcellus shale areas.

Great Lakes

In November 2013, we received FERC approval for a rate settlement with our shippers resulting in maximum recourse rates increasing by approximately 21 per cent resulting in a modest increase in revenues derived from our recourse rate contracts. The settlement includes a 17 month moratorium through March 2015 and requires us to have new rates in effect by January 1, 2018.

Mexican Pipelines

Topolobampo and Mazatlan Pipeline Projects.
Permitting and engineering activities are advancing as planned for these two northwest Mexico pipelines. The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver gas from El Encino, Chihuahua and interconnects with third party pipelines in El Oro, Sinaloa to Topolobampo, Sinaloa. The Mazatlan project is a 413 km (257 miles), 24-inch pipeline running from El Oro to Mazatlan, within the state of Sinaloa with a capacity of 200 MMcf/d and an estimated cost of US$400 million. Both projects are supported by 25-year contracts with the Comisión Federal de Electricidad (CFE) and are expected to be in service mid to late 2016.

Tamazunchale Pipeline Extension Project
The construction of the US$500 million Tamazunchale Pipeline Extension project is proceeding although delays have occurred due to a significant number of archeological finds within the pipeline route. It is expected these findings and related alternative construction will move the project scheduled in-service date to second quarter 2014. As these types of findings are not uncommon in significant infrastructure projects in Mexico, contractual relief for such delays is provided. We continue to work with local, state and federal authorities to minimize and mitigate ground disturbance at the specific sites as well as to minimize impact to the scheduled in-service date.

LNG Pipeline Projects

Coastal GasLink
In June 2012, we were selected to design, build, own and operate the proposed Coastal GasLink project. The estimated $4 billion, 650 km (404 miles) pipeline is expected to have an initial capacity of 1.7 Bcf/d and will transport natural gas from the Montney gas producing region near Dawson Creek B.C. to LNG Canada's proposed LNG export facility near Kitimat B.C.

We are currently focused on community, landowner, government and First Nations engagement as the project advances through the regulatory process. We filed the Application for an Environmental Assessment Certificate with the B.C. Environmental Assessment Office (BCEAO) in January 2014.

The pipeline would be placed in service near the end of the decade, subject to a final investment decision to be made by LNG Canada after obtaining final regulatory approvals. We continue to advance this project and all costs would be recoverable should the project not proceed.

Prince Rupert Gas Transmission Project
We have been selected to design, build, own and operate the proposed $5 billion, 750 km (466 miles) Prince Rupert Gas Transmission Project. The 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 are currently focused on First Nations, community, landowner and government engagement as the Prince Rupert pipeline project advances through the regulatory process with the BCEAO. We continue to refine our study corridor based on consultation and detailed studies to date. A final investment decision to construct the project, for a planned in-service date of late 2018, is expected to be made following final regulatory approvals.

We continue to advance this project and all costs would be fully recoverable should the project not proceed.

Alaska LNG Project
The State of Alaska is proposing new legislation that would transition from the *Alaska Gasline Inducement Act* and enable a new commercial arrangement to be established with us, the three major producers, and the Alaska Gasline Development Corp. It has also been agreed that an LNG export project, rather than a pipeline

to Alberta, is currently the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. It is anticipated that two years of front end engineering will be completed before further commitments to commercialize the project will be made.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 76 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 largely on supply from the WCSB. There is competition for this supply from several pipelines, demand within the basin, and in the future, demand for pipelines proposed for LNG exports from the west coast of B.C. An overall decrease in production and/or competing demand for supply, could impact throughput on WCSB connected pipelines that in turn could impact overall revenues generated. The WCSB has considerable reserves, but how much of it is actually produced will depend on many variables, including the price of natural gas, basin-on-basin competition, downstream pipeline tolls, demand within the basin 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 basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines that may impact revenue. 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 for greenfield expansion

We face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline 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. Renewal of expiring contracts, and the opportunity to charge and collect a toll the market requires depends on the overall demand for transportation service. A change in the level of demand for our pipeline transportation services could impact revenues.

Regulatory risk

Decisions by regulators can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable that could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion or all prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects including the time it takes to receive a decision could be slowed or unfavorable due to the influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies, has the potential to increase operating costs. There is a risk of an impact to revenues if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

Operational

Keeping our pipelines operating safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced revenue and can affect corporate reputation as well as customer and public confidence in our operations. 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

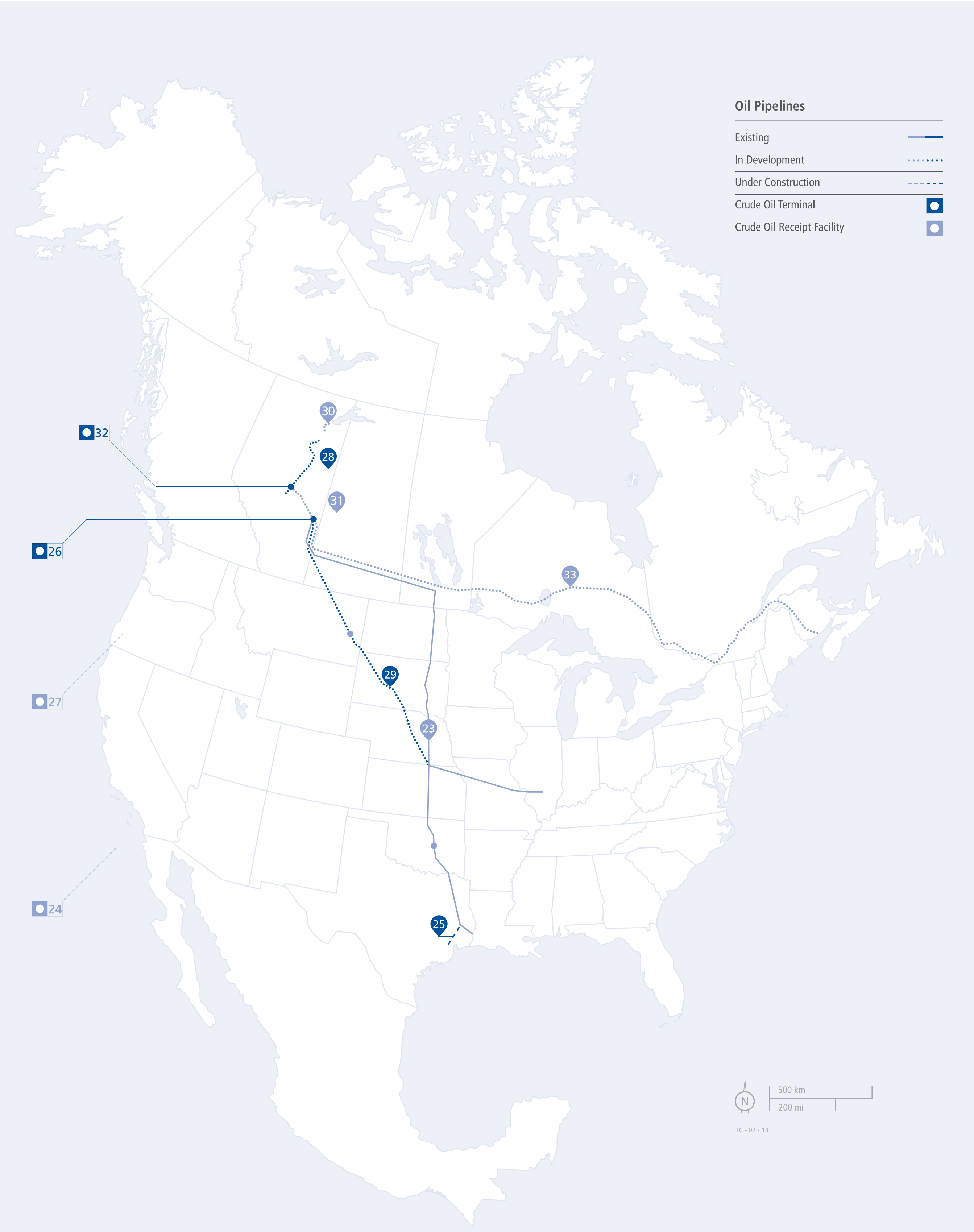
Our existing crude oil pipeline infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S Gulf Coast.

Strategy at a glance

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

We continue to focus on accessing and delivering growing North American crude oil supply to key markets, and are planning to expand our crude oil transportation infrastructure to deliver supply directly from the production site seamlessly along a contiguous path to the market.

Construction of these infrastructure projects will provide North America with a key crude oil transportation network to transport growing crude oil supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.


Oil Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
Crude Oil Receipt Facility
32
26
27
24
30
28
31
33
29
23
25
500 km
200 mi
N
TC - 02 - 13

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

		length	description	ownership
	Oil pipelines			
23	Keystone Pipeline System (includes Gulf Coast Project)	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka in Illinois, Cushing, Oklahoma, and to the U.S. Gulf Coast refining market	100%
	Under construction			
24	Cushing Marketlink Receipt Facility	Crude oil receipt facilities	To facilitate the transportation of crude oil from the market hub at Cushing, Oklahoma to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System	100%
25	Houston Lateral and Terminal	77 km (48 miles)	To transport crude oil from the Keystone Pipeline System to Houston, Texas	100%
26	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 access to the Keystone Pipeline System	100%
	In development			
27	Bakken Marketlink Receipt Facility	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%
28	Grand Rapids Pipeline	500 km (300 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland market region	50%
29	Keystone XL	1,897 km (1,179 miles)	Crude oil pipeline from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
30	Northern Courier Pipeline	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
31 32	Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
33	Energy East Pipeline	4,500 km (2,700 miles)	To transport crude oil from western Canada to eastern refineries and export markets	100%

RESULTS

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**[1]
Keystone Pipeline System	**766**	712	589
Oil Pipelines Business Development	**(14)**	(14)	(2)
Oil Pipelines – comparable EBITDA	**752**	698	587
Comparable depreciation and amortization	**(149)**	(145)	(130)
Oil Pipelines – comparable EBIT	**603**	553	457
Comparable EBIT denominated as follows			
Canadian dollars	**201**	191	159
U.S. dollars	**389**	363	301
Foreign exchange impact	**13**	(1)	(3)
Oil Pipelines – comparable EBIT	**603**	553	457

1 Results in 2011 are for 11 months.

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $54 million higher this year than in 2012. This increase reflected higher revenues primarily resulting from:

- higher volumes
- the impact of higher final fixed tolls on committed pipeline capacity to Cushing, Oklahoma, which came into effect in July 2012.

Results in 2013 were positively impacted by the stronger U.S. dollar compared to 2012.

Comparable EBITDA for the Keystone Pipeline System was $123 million higher in 2012 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 recorded in 2012 compared to eleven months in 2011.

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 in 2012 were $12 million higher than 2011 mainly because of increased business development activity on various oil pipeline development projects.

Comparable depreciation and amortization

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

OUTLOOK

Earnings

We expect earnings to increase in 2014 compared to 2013, due to the completion of the Gulf Coast segment of the Keystone Pipeline System allowing commencement of crude oil transportation services to the U.S. Gulf Coast. Earnings are expected to increase over time as projects currently in development are placed in service.

Capital expenditures

We spent a total of $2.5 billion in 2013, and expect to spend approximately $2.3 billion in 2014, mainly related to Heartland Pipeline, Northern Courier Pipeline and Grand Rapids Pipeline. This amount excludes Keystone XL. The amount and timing of capital spending on Keystone XL will be dependent on the decision by the DOS to issue a Presidential Permit. See page 82 for further discussion on liquidity risk.

UNDERSTANDING THE OIL PIPELINES BUSINESS

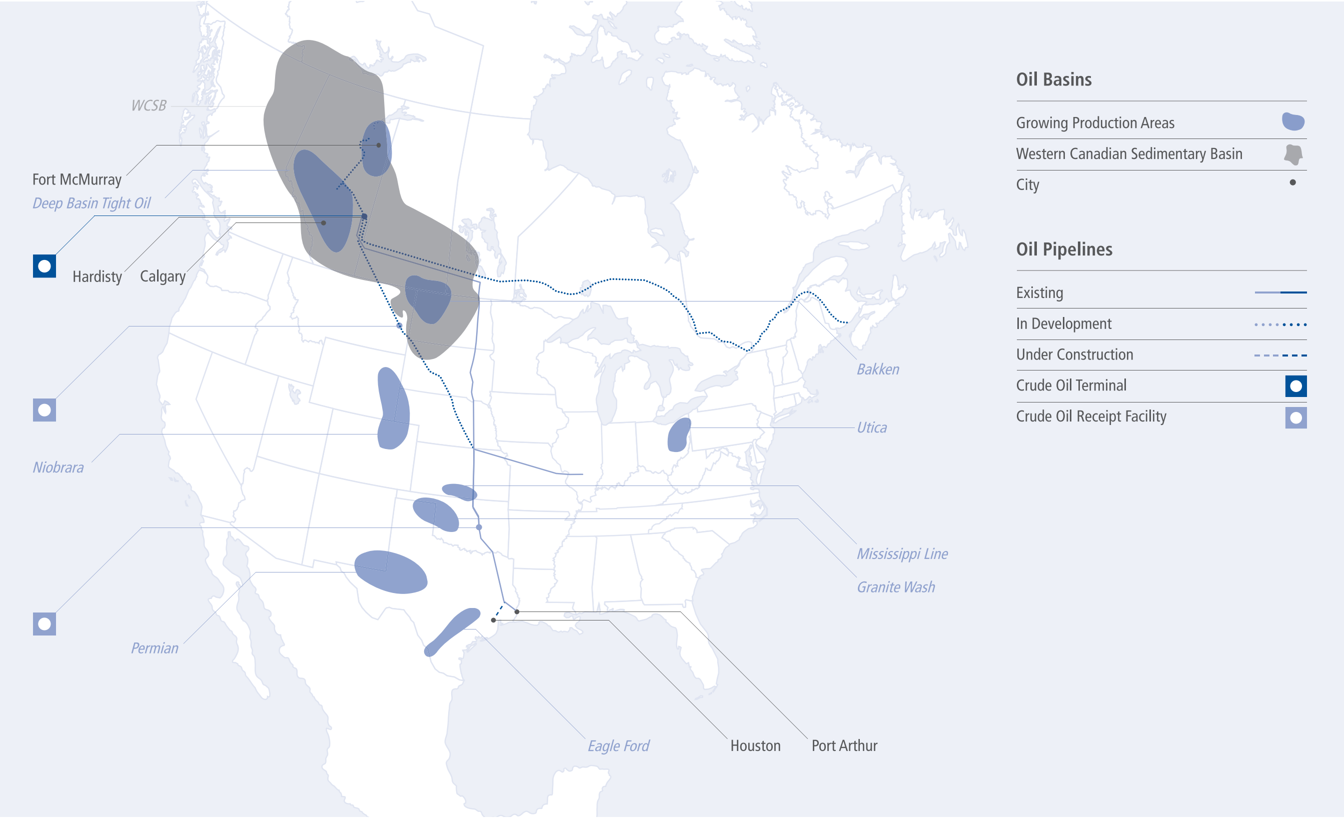
Oil pipelines move crude oil from major supply sources to refinery markets so the crude oil can be refined into various petroleum products.

We generate earnings from our oil pipelines mainly by providing pipeline capacity to shippers 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 which provides opportunities to generate incremental earnings.

The terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These arrangements are typically long term, and provide for the recovery of costs we incur to construct and 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 a 2013 Canadian Association of Petroleum Producers (CAPP) report, the WCSB produced an estimated 1.2 million Bbl/d of conventional crude oil and condensate, and 1.8 million Bbl/d of Alberta oil sands crude oil – a total of approximately 3.0 million Bbl/d. The production of conventional crude oil in western Canada continues to grow with 2012 to 2013 growth representing the largest year over year change to the previous forecast.

In its 2013 report, the Alberta Energy Regulator (AER) estimated there are approximately 170 billion barrels of remaining established conventional and oil sands reserves in Alberta. In June 2013, CAPP forecasted WCSB crude oil supply would increase to 3.9 million Bbl/d by 2015 and to 4.9 million Bbl/d by 2020. Its 2013 forecast for western Canadian production of conventional and unconventional crude oil in 2025 is 300,000 Bbl/d higher than its forecast in 2012.

Oil sands production

Despite increases in production from conventional sources and new shale oil production (including the Canadian Bakken and Cardium formations), the oil sands will continue to make up most of the crude oil production from the WCSB. CAPP estimated that industry capital spending on oil sands development held steady at $23 billion for 2013.

Oil sands projects have a long reserve life. According to the Responsible Canadian Energy Report issued by CAPP, it is estimated that a typical oil sands mine has a 25 to 50 year lifespan and an in-situ operation will run

10 to 15 years on average. That aligns with producers' desire to secure long-term connectivity of their reserves to market. The Keystone Pipeline System and the proposed Energy East Pipeline will provide producers with needed pipeline capacity and are underpinned by long term commercial contracts.

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, Alberta and which can also move diluent from Edmonton/Heartland region to the production area in Northern Alberta. We are constructing the Heartland Pipeline and TC Terminals projects to support these market hubs which allow shippers the ability to connect with the Keystone Pipeline System, Energy East Pipeline and other pipelines that transport crude oil outside of Alberta.

Growth in U.S. production

According to the International Energy Agency World Energy Outlook 2013 report, by 2015, the U.S. is set to surpass Saudi Arabia as the world's largest oil producer. The U.S. Energy Information Administration (EIA) projects nearly 2.0 million Bbl/d of U.S. production growth, peaking at 9.6 million Bbl/d by 2019. Higher production volumes result mainly from shale oil production. EIA forecasts approximately 4.8 million Bbl/d of shale oil production by 2020 and declining by 2022.

Shale oil supply growth is mainly from the Bakken formation of the Williston basin in North Dakota and Montana, the Permian basin in south Texas and Woodford shale area of the Arkoma basin in Oklahoma. These shale production areas represent some of the sources of crude oil supply for our Bakken and Cushing Marketlink projects.

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, Oklahoma and the U.S. Gulf Coast refining market. Our Gulf Coast segment of the Keystone Pipeline System and Cushing Marketlink project provide needed pipeline capacity to transport growing crude oil supply at Cushing, Oklahoma to the U.S. Gulf Coast.

Even with growth in U.S. crude oil production, the EIA report predicts the U.S. will remain a net importer of crude oil, importing 7.7 million Bbl/d into 2040. Growing production in the west Texas Permian, south Texas Eagle Ford and Williston basins, is primarily light crude oil, and is expected to compete with light imports from countries such as Nigeria and Saudi Arabia. Gulf Coast refiners are expected to continue to prefer Canadian heavy crude oil because their refineries are mainly configured to process heavy crude oil and cannot easily switch to processing the new light shale oil in large quantities without significant capital investments. Gulf Coast refineries currently require approximately 3.5 million Bbl/d of heavy and medium crude oil, and the level of demand is not expected to change significantly in the future. The Keystone Pipeline System is well positioned to deliver Canadian crude oil to this significant market.

Refineries in eastern Canada currently process primarily 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 significantly 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 anticipate that our Energy East Pipeline project, once approved and constructed, will meet this demand.

SIGNIFICANT EVENTS

Keystone Pipeline System

We finished constructing the 780 km (485 miles) 36-inch pipeline of the Gulf Coast project, an extension of the Keystone Pipeline System, from Cushing, Oklahoma to the U.S. Gulf Coast. Crude oil transportation service on the project began January 22, 2014. We are projecting an average pipeline capacity of 520,000 Bbl/d for the first year of operation.

Houston Lateral and Terminal

Construction continues on the US$400 million, 77 km (48 miles) Houston Lateral pipeline and tank terminal to transport crude oil to Houston, Texas refineries. We anticipate the capacity of the lateral will be similar to that of the Gulf Coast project and the terminal is expected to have initial storage capacity for 700,000 barrels of crude oil. The pipeline and terminal are expected to be completed in mid-2015.

Cushing Marketlink

Construction continues on the Cushing Marketlink receipt facilities at Cushing, Oklahoma. Cushing Marketlink will facilitate the transportation of crude oil from the market hub at Cushing to the U.S. Gulf Coast refining market on facilities that form part of the Keystone Pipeline System. Construction is expected to be completed in the first half of 2014.

Keystone XL

In March 2013, the DOS released its Draft Supplemental Environmental Impact Statement for the Keystone XL project. The impact statement reaffirmed construction of the 830,000 Bbl/d Keystone XL project would not result in any significant impact to the environment.

On January 31, 2014, the DOS released its Final Supplemental Environmental Impact Statement (FSEIS) for the Keystone XL project. The results included in the report were consistent with previous environmental reviews of Keystone XL. The FSEIS concluded Keystone XL is "unlikely to significantly impact the rate of extraction in the oil sands" and that all other alternatives to Keystone XL are less efficient methods of transporting crude oil, and would result in significantly more greenhouse gas emissions, oil spills and risks to public safety. The report initiated the National Interest Determination period of up to 90 days which involves consultation with other governmental agencies and provides an opportunity for public comment.

On February 19, 2014, a Nebraska district court ruled that the state Public Service Commission, rather than Governor Dave Heineman, has the authority to approve an alternative route through Nebraska for the Keystone XL project. We disagree with the decision of the Nebraska district court and will now analyze the judgment and decide what next steps may be taken. Nebraska's Attorney General has filed an appeal.

We anticipate the pipeline, which will extend from Hardisty, Alberta to Steele City, Nebraska, to be in service approximately two years following the receipt of the Presidential Permit. The US$5.4 billion cost estimate will increase depending on the timing and conditions of the permit. Any capital cost increase above the initial estimated capital cost, up to a specified amount, is shared between us and the shippers such that 75 per cent of the change in capital cost is reflected in the fixed payment received by us. Any capital cost increase above the specified amount is shared equally between us and the shippers. As of December 31, 2013, we have invested US$2.2 billion in the project.

Energy East Pipeline

In August 2013, we announced we are moving forward with the 1.1 million Bbl/d Energy East Pipeline as it received approximately 900,000 Bbl/d of firm, long-term contracts in its open season to transport crude oil from western Canada to eastern refineries and export terminals. The project is estimated to cost approximately $12 billion, excluding the transfer value of Canadian Mainline natural gas assets.

Subject to regulatory approvals, the pipeline is anticipated to commence deliveries to Québec in 2018, with service to New Brunswick expected to follow in late 2018. We have begun Aboriginal and stakeholder engagement and associated field work as part of our initial design and planning. We intend to file the necessary regulatory applications in mid-2014 for approvals to construct and operate the pipeline project and terminal facilities.

Northern Courier Pipeline

In April 2013, we filed a permit application with the AER after completing the required Aboriginal and stakeholder engagement and associated field work.

In October 2013, Suncor Energy announced that the Fort Hills Energy Limited Partnership is proceeding with the Fort Hills oil sands mining project and expects to begin producing crude oil in 2017. Our Northern Courier Pipeline project is expected to cost $800 million and will transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.

Heartland Pipeline and TC Terminals

In May 2013, we announced we had reached binding long-term shipping agreements to build, own and operate the Heartland Pipeline and TC Terminals projects.

The projects will include a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta, and a terminal facility in the Heartland industrial area north of Edmonton, Alberta. We anticipate the pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have storage capacity for up to 1.9 million barrels of crude oil. These projects together have a combined cost estimated at $900 million and are expected to be placed in service in 2016.

We filed a permit application for the terminal facility in May 2013 and for the pipeline in October 2013 with the AER, after completing the required Aboriginal and stakeholder engagement and associated field work. In February 2014, the application for the terminal facility was approved.

Keystone Hardisty Terminal

In May 2013, we started construction on the Keystone Hardisty Terminal which we anticipate will have a storage capacity of up to 2.6 million barrels of crude oil. The $300 million crude oil terminal at Hardisty, Alberta is expected to be in service in 2016.

Grand Rapids Pipeline

In May 2013, we filed a permit application for the Grand Rapids Pipeline with the AER after completing the required Aboriginal and stakeholder engagement and associated field work. The dual pipeline system could transport up to 900,000 Bbl/d of crude oil and 330,000 Bbl/d of diluent.

Along with a partner, we will each own 50 per cent of the project and we will operate the system, which is expected to cost $3 billion. Our partner has entered into a long-term commitment to ship crude oil and diluent on this pipeline system.

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

BUSINESS RISKS

The following are risks specific to our oil pipelines business. See page 76 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 pipelines is essential to the success of our oil pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed 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 may also have an adverse 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

We make substantial capital commitments in large infrastructure projects 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, increased capital cost 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 hydraulic fracturing 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 that crude 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, re-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, Permian and Arkoma basins crude oil supplies to key North American refining markets and export 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 the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Energy

Our 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.

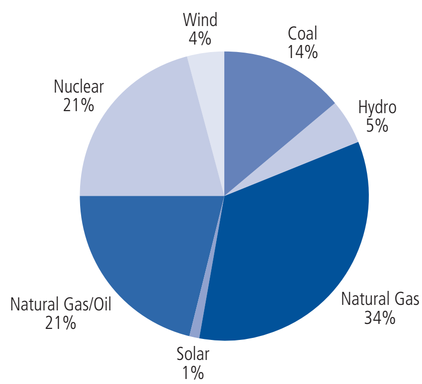
Strategy at a glance

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 creditworthy counterparties. Our growing investment in natural gas, nuclear, wind, hydro-power and solar generating facilities demonstrates our commitment to clean, sustainable energy.

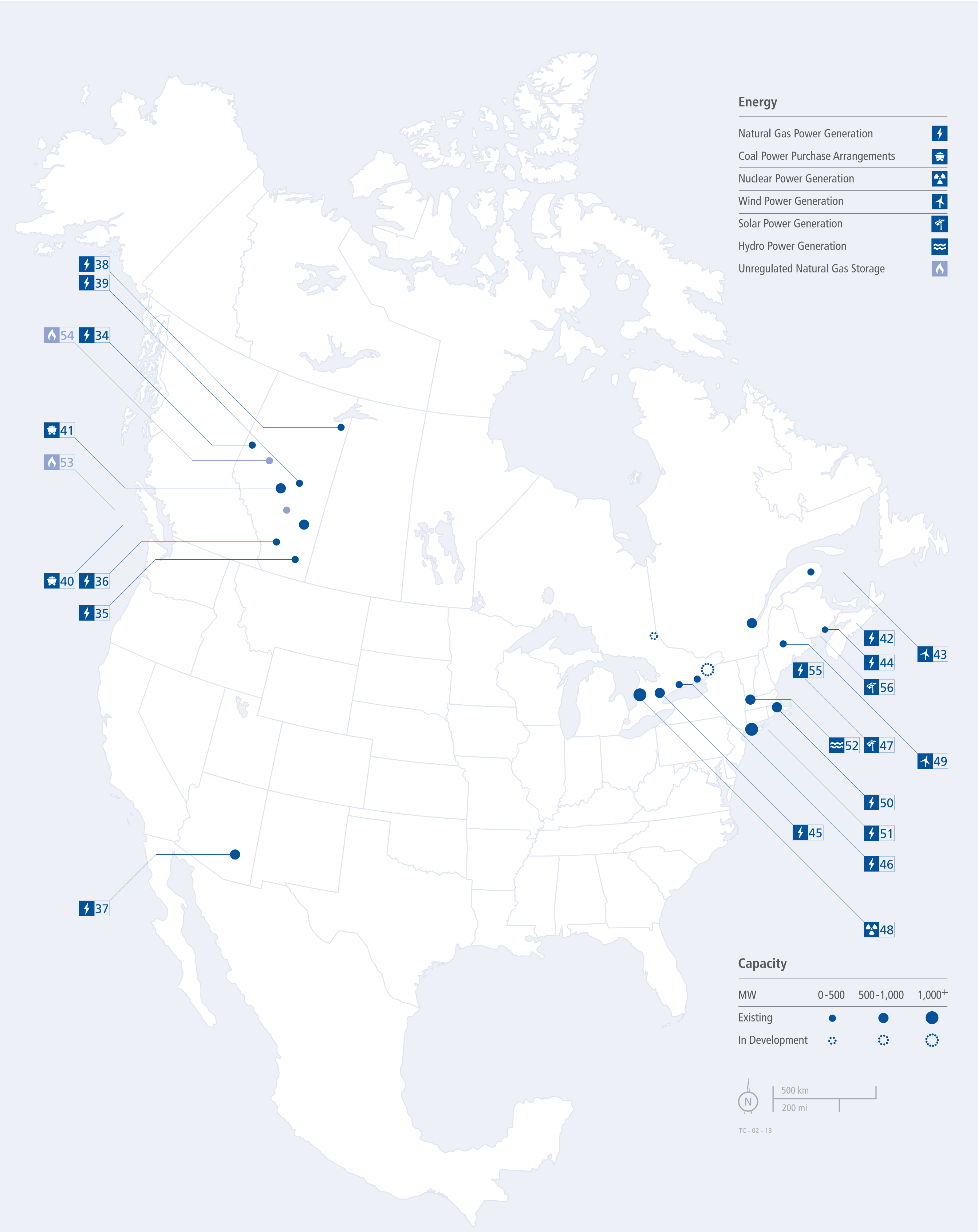
The growth in demand for power in North America coupled with an electrical infrastructure base that is aging and a societal preference for lower carbon intense electricity production is expected to provide us with the opportunity to participate in new generation and other power infrastructure projects.

Natural gas storage's role in balancing and providing reliability and flexibility to the natural gas system is expected to grow as the market expands and becomes more dynamic as a result of the electric grid's increased reliance on gas-fired capacity to backup ever increasing renewable power and from the addition of LNG export terminals.

Power by Fuel Source[1]



[1] Includes facilities in development.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Energy
Natural Gas Power Generation
Coal Power Purchase Arrangements
Nuclear Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Unregulated Natural Gas Storage
Capacity
MW
0-500
500-1,000
1,000+
Existing
In Development
N
500 km
200 mi
TC - 02 - 13

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.					
34	Bear Creek	80	natural gas	Cogeneration plant	Grand Prairie, Alberta	100%
35	Cancarb[1]	27	natural gas, waste heat	Facility fuelled by waste heat from an adjacent TransCanada facility that produces thermal carbon black, a by-product of natural gas	Medicine Hat, Alberta	100%
36	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
37	Coolidge[2]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
38	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
39	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
40	Sheerness PPA	756	coal	PPA for entire output of facility	Hanna, Alberta	100%
41	Sundance A PPA	560	coal	PPA for entire output of facility	Wabamun, Alberta	100%
41	Sundance B PPA (Owned by ASTC Power Partnership[3])	353[4]	coal	PPA for entire output of facility	Wabamun, Alberta	50%
	Eastern Power 2,950 MW of power generation capacity (including facilities in development)					
42	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
43	Cartier Wind	366[4]	wind	Five wind power projects	Gaspésie, Québec	62%
44	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
45	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
46	Portlands Energy	275[4]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
47	Ontario Solar	36	solar	Four solar facilities	Southern Ontario	100%

		generating capacity (MW)	type of fuel	description	location	ownership
	Bruce Power 2,484 MW of power generation capacity through eight nuclear power units					
48	Bruce A	1,462[4]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
48	Bruce B	1,022[4]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%
	U.S. Power 3,755 MW of power generation capacity					
49	Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
50	Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
51	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%
52	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					
53	CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
54	Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
	In development					
55	Napanee	900	natural gas	Proposed combined-cycle plant	Greater Napanee, Ontario	100%
56	Ontario Solar	50	solar	Acquisition of five remaining solar facilities from Canadian Solar Solutions Inc. in 2014	Southern Ontario and New Liskeard, Ontario	100%

1 As at December 31, 2013, both the Cancarb waste heat and thermal carbon black plant were classified as Assets Held for Sale. See Significant Events for further information

2 Located in Arizona, results reported in Canadian Power – Western Power.

3 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.

4 Our share of power generation capacity.

RESULTS

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Canadian Power			
Western Power[1]	**380**	335	483
Eastern Power[2]	**347**	345	297
Bruce Power	**310**	14	110
General, administrative and support costs	**(50)**	(48)	(43)
Canadian Power – comparable EBITDA[3]	**987**	646	847
Comparable depreciation and amortization	**(172)**	(152)	(141)
Canadian Power – comparable EBIT[3]	**815**	494	706
U.S. Power (US$)			
Northeast Power	**370**	257	314
General, administrative and support costs	**(47)**	(48)	(41)
U.S. Power – comparable EBITDA	**323**	209	273
Comparable depreciation and amortization	**(107)**	(121)	(109)
U.S. Power – comparable EBIT	**216**	88	164
Foreign exchange impact	**7**	-	(4)
U.S. Power – comparable EBIT (Cdn$)	**223**	88	160
Natural Gas Storage and other			
Natural Gas Storage and other	**73**	77	84
General, administrative and support costs	**(10)**	(10)	(6)
Natural Gas Storage and other – comparable EBITDA[3]	**63**	67	78
Comparable depreciation and amortization	**(12)**	(10)	(12)
Natural Gas Storage and other – comparable EBIT[3]	**51**	57	66
Business development comparable EBITDA and EBIT	**(20)**	(19)	(25)
Energy – comparable EBIT[3]	**1,069**	620	907
Summary			
Energy – comparable EBITDA[3]	**1,363**	903	1,168
Comparable depreciation and amortization	**(294)**	(283)	(261)
Energy – comparable EBIT[3]	**1,069**	620	907

1 Includes Coolidge starting in May 2011.
2 Includes the acquisition of four Ontario Solar facilities in 2013 and 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.
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 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA for Energy was $460 million higher in 2013 than in 2012. The increase was the effect of:

- higher equity income from Bruce Power due to incremental earnings from Units 1 and 2 and lower planned outage days at Unit 4 and an insurance recovery related to the May 2012 Unit 2 electrical generation failure
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices
- higher earnings from Western Power primarily because of higher purchased volumes under the PPAs.

Comparable EBITDA for Energy was $265 million lower in 2012 compared to 2011. This reflected the net effect of:

- lower earnings from Western Power due to the Sundance A 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
- lower earnings from U.S. Power because of lower realized power prices, higher load serving costs and reduced water flows at the TC Hydro facilities.

OUTLOOK

Earnings

We expect 2014 earnings from the Energy segment to be slightly lower than 2013, assuming the net effect of:

- lower power prices and lower seasonal natural gas storage price spreads in Alberta
- lower earnings as a result of the sale of Cancarb
- higher realized capacity prices and commodity prices in New York and New England
- incremental earnings from the solar facilities acquired in 2013, as well as the additional facilities expected to be acquired in 2014, offset by lower contributions from Bécancour.

Bruce Power equity income is expected to be consistent with 2013.

Although a significant portion of Energy's output is sold under long-term contracts, revenue from power that is sold under shorter-term forward arrangements or at spot prices will continue to be impacted by fluctuations in commodity prices and changes in seasonal natural gas storage price spreads will impact Natural Gas Storage earnings.

Weather, unplanned outages and unforeseen regulatory changes can play a role in spot markets.

Western Power

Alberta power market fundamentals are strong and new power capacity and transmission projects are being developed to meet growing demand. In step with economic growth, Alberta power demand in 2013 was 2.5 per cent higher than 2012, an annual rate that has been relatively consistent since 2009. The outlook for forward oil prices supports ongoing investment in the oil sands and the associated development is expected to support continuing economic growth and increased power consumption in the province of Alberta. The Alberta Electric System Operator is forecasting that demand growth will continue to be strong at a three per cent plus annual increase over the next 10 years, and estimates that about 7,000 MW of new generation will be required.

The strong growth will afford us ample opportunity to participate in new generation additions and other power infrastructure projects. Spot market power prices are a function of many factors, including supply and demand conditions and natural gas prices. The supply of power is largely dictated by the performance of the coal fleet and wind availability, while power demand is highly influenced by weather and seasonal factors. Average spot market power prices in Alberta in 2013 ($80/MWh) were higher than 2012 ($64/MWh) partly due to three significant long-term coal unit outages, demand growth and higher natural gas prices. In 2014, modest supply additions combined with fewer long-term coal unit outages are expected to result in lower spot prices that are more in line with long run historical price levels.

Natural Gas Storage

Natural gas spreads are currently in cyclical lows with 2014 forward summer/winter spreads below the average experienced in 2013. The strength of summer prices relative to winter will be heavily influenced by season ending storage inventory levels and increased summer flows out of Alberta.

Eastern Power

All of our existing energy assets in Eastern Power are fully contracted. Our Ontario assets are contracted with the Ontario Power Authority (OPA) and, as a result, we are largely shielded from fluctuations in the spot price of electricity in Ontario. The Ontario Independent Electricity System Operator forecasts slight growth in the demand for power in 2014 as conservation programs and embedded generation offset consumption gains related to stronger economic growth. At the end of 2013, Ontario had retired the majority of its coal-fired fleet.

Bruce Power

In late 2013, the Ontario government released an updated Long-term Energy Plan that introduced a nuclear refurbishment policy framework for select nuclear units, including the Bruce Power facilities that we partially own. Bruce Power is considering the implications of the updated Long-term Energy Plan and the site's refurbishment options.

U.S. Power

U.S. northeast power market areas are expected to have minor growth in load demand in 2014. A larger source of potential growth for power prices will be the expected higher natural gas prices due to the limited import capability into the U.S. northeast markets and better fundamental support with larger 2013/2014 winter season withdrawals from storage.

Average New England ISO power prices increased to US$56/MWh in 2013 from US$36/MWh in 2012, primarily driven by higher gas prices. New England power demand increased by approximately one and a half per cent in 2013 compared to 2012, partly due to cold winter weather and modest gains in the economy. The New England ISO forecasts growth in the demand for power of about one and a half per cent per year in the coming years, centred on modest economic growth.

Power demand in New York City in 2013 was similar to 2012, primarily due to tepid economic growth conditions and a cool second half of the summer; however, the average New York ISO power price for New York City increased to US$52/MWh in 2013, compared to approximately US$39/MWh in 2012, as a result of higher natural gas prices. The New York ISO forecasts New York City power demand will grow at a rate of 0.5 per cent per year over the next decade, based on modest growth in the population and the economy.

Our northeastern U.S. power facilities also earn significant revenues through participation in regional capacity markets. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. New England ISO's forward capacity market auction prices have been set at US$2.75/kW month for 2014 with prorated prices coming in slightly higher compared to US$2.50/kW month in 2013. In New York, new demand curve parameters were recently set by FERC order to take effect in summer 2014 and have been modestly reduced compared to the parameters presently in place. Combined with other factors affecting the supply and demand for capacity, including the net effect of these new parameters, capacity prices in 2014 are expected to modestly improve over those realized in 2013. For further information on these developments please see Energy – Significant Events on page 62.

Capital expenditures

We spent a total of $152 million in 2013, and expect to spend approximately $270 million on capital expenditures in Energy in 2014. See page 82 for further discussion on liquidity risk.

Equity investments and acquisitions

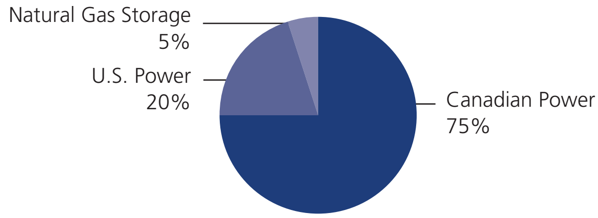
In 2013, we also invested $216 million on the acquisition of four Ontario solar facilities and $63 million in Bruce Power for capital projects. We expect to spend approximately $280 million on the acquisition of the remaining five Ontario solar facilities and $90 million on Bruce Power investments in 2014.

UNDERSTANDING THE ENERGY BUSINESS

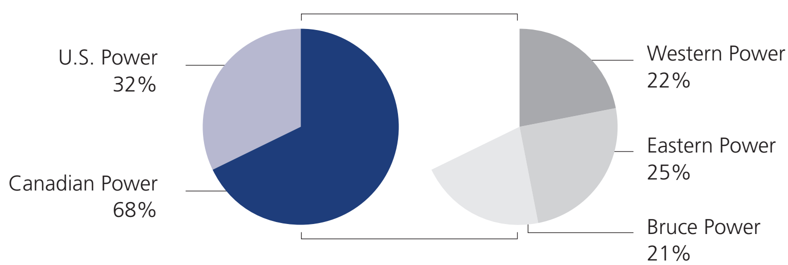
Our Energy business is made up of three groups:

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

Energy comparable EBIT – contribution by group, excluding business development expenses
year ended December 31, 2013



Power generation capacity – contribution by group
year ended December 31, 2013 (includes facilities in development)



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 per cent through our ASTC Power 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.

The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

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 long-term contracts.

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
Ontario Solar[2]	20-year Feed-in Tariff (FIT) contracts	OPA	2033

1 Power generation has been suspended since 2008.
2 We acquired four facilities in 2013 and expect to acquire the remaining five facilities in 2014.

Assets currently in development are as follows:

	Type of contract	With	Expires
Ontario Solar[1]	20-year FIT contracts	OPA	20 years from in-service date
Napanee	20-year Clean Energy Supply contract	OPA	20 years from in-service date

1 We acquired four facilities in 2013 and expect to acquire the remaining five facilities in 2014.

Western and Eastern Power results[1,2]

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	2013	2012	2011
Revenue			
Western power[1]	**609**	640	822
Eastern power[2]	**400**	415	391
Other[3]	**108**	91	69
	1,117	1,146	1,282
Income from equity investments[4]	**141**	68	117
Commodity purchases resold			
Western power	**(277)**	(281)	(368)
Other[5]	**(6)**	(5)	(9)
	(283)	(286)	(377)
Plant operating costs and other	**(248)**	(218)	(242)
Sundance A PPA arbitration decision – 2012	**-**	(30)	-
General, administrative and support costs	**(50)**	(48)	(43)
Comparable EBITDA	**677**	632	737
Comparable depreciation and amortization	**(172)**	(152)	(141)
Comparable EBIT	**505**	480	596
Breakdown of comparable EBITDA			
Western power	**380**	335	483
Eastern power	**347**	345	297
General, administrative and support costs	**(50)**	(48)	(43)
Comparable EBITDA	**677**	632	737

1 Includes Coolidge starting in May 2011.
2 Includes the acquisition of four Ontario Solar facilities in 2013, 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.
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.

Sales volumes and plant availability[1,2]

Includes our share of volumes from our equity investments.

year ended December 31	2013	2012	2011
Sales volumes (GWh)			
Supply			
Generation			
Western power[1]	**2,728**	2,691	2,606
Eastern power[2]	**3,822**	4,384	3,714
Purchased			
Sundance A & B and Sheerness PPAs[3]	**8,223**	6,906	7,909
Other purchases	**13**	46	248
	14,786	14,027	14,477
Sales			
Contracted			
Western power[1]	**7,864**	8,240	8,381
Eastern power[2]	**3,822**	4,384	3,714
Spot			
Western power	**3,100**	1,403	2,382
	14,786	14,027	14,477
Plant availability[4]			
Western power[1,5]	**95%**	96%	97%
Eastern power[2,6]	**90%**	90%	93%

1 Includes Coolidge starting in May 2011.
2 Includes the acquisition of four Ontario Solar facilities in 2013, 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. Also includes volumes related to our 50 per cent ownership interest in Portlands Energy.
3 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in early September 2013 and Unit 2 returned to service in early October 2013.
4 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.
5 Does not include facilities that provide power to us under PPAs.
6 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA in 2013 was $45 million higher than in 2012. The increase was mainly due to increased volumes purchased under the PPAs and sold at realized power prices that were comparable to levels achieved in 2012.

The Alberta power market continued to be strong during 2013. Alberta power demand in 2013 was 2.5 per cent higher than 2012. Average spot market power prices in Alberta were $80/MWh in 2013, or 25 per cent higher than 2012, partly due to three significant long-term coal unit outages, demand growth and higher natural gas prices. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

Purchased volumes in 2013 were higher than 2012 mainly because of the return to service of the Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013 and increased volumes under the Sundance B PPA.

Western Power's comparable EBITDA in 2012 was $148 million lower than 2011. This was primarily due to the net effect of:

- the Sundance A force majeure resulting in no earnings recorded in 2012

- lower purchased PPA volumes during periods of lower spot prices
- incremental earnings from Coolidge, which was placed in service in May 2011
- higher realized power prices as a result of contracting activities.

Approximately 72 per cent of Western Power sales volumes were sold under contract in 2013 compared to 85 per cent in 2012 and 78 per cent in 2011.

Eastern Power

Eastern Power's comparable EBITDA in 2013 was similar to 2012, due to the net effect of:

- incremental earnings from Cartier and from the four Ontario solar facilities acquired in 2013
- lower contractual earnings at Bécancour.

In 2012, Eastern Power's comparable EBITDA was $48 million higher than 2011 mainly due to:

- incremental earnings from Cartier
- higher contractual earnings at Bécancour.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of Bruce A and Bruce B. Bruce A Units 1 to 4 have a combined capacity of approximately 3,000 MW and Bruce B Units 5 to 8 have a combined capacity of approximately 3,200 MW. Bruce B leases the eight nuclear reactors from Ontario Power Generation and subleases Units 1 to 4 to Bruce A.

Bruce Power's generating capacity is fully contracted with the OPA. Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

Under the contract with the OPA, all of the output from Bruce A is sold at a fixed price/MWh. The fixed price is adjusted annually on April 1 for inflation and other provisions under the OPA contract. Bruce A also recovers fuel costs from the OPA.

Bruce A fixed price	Per MWh
April 1, 2013 – March 31, 2014	$70.99
April 1, 2012 – March 31, 2013	$68.23
April 1, 2011 – March 31, 2012	$66.33

Under the same contract, all output from Bruce B Units 5 to 8 is subject to a floor price adjusted annually for inflation on April 1.

Bruce B floor price	Per MWh
April 1, 2013 – March 31, 2014	$52.34
April 1, 2012 – March 31, 2013	$51.62
April 1, 2011 – March 31, 2012	$50.18

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the monthly average spot price exceeds the floor price. Bruce Power has not had to repay any amounts in the past three years.

Bruce B also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

Bruce Power results

Our proportionate share

year ended December 31 (millions of $, unless otherwise indicated)	**2013**	**2012**	**2011**
Income/(loss) from equity investments[1]			
Bruce A	**202**	(149)	33
Bruce B	**108**	163	77
	310	14	110
Comprised of:			
Revenues	**1,258**	763	817
Operating expenses	**(618)**	(567)	(565)
Depreciation and other	**(330)**	(182)	(142)
	310	14	110
Bruce Power – other information			
Plant availability[2]			
Bruce A[3]	**82%**	54%	90%
Bruce B	**89%**	95%	88%
Combined Bruce Power	**86%**	81%	89%
Planned outage days			
Bruce A	**123**	336	60
Bruce B	**140**	46	135
Unplanned outage days			
Bruce A	**63**	18	16
Bruce B	**20**	25	24
Sales volumes (GWh)[1]			
Bruce A[3]	**10,033**	4,194	5,475
Bruce B	**7,824**	8,475	7,859
	17,857	12,669	13,334
Realized sales price per MWh[4]			
Bruce A	**$70**	$68	$66
Bruce B	**$54**	$55	$54
Combined Bruce Power	**$62**	$57	$57

1 Represents our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. Sales volumes exclude deemed generation.
2 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.
3 Plant availability and sales volumes for 2013 and 2012 include the incremental impact of Unit 1 and Unit 2 which were returned to service in October 2012.
4 Calculation based on actual and deemed generation. Bruce B realized sales prices per MWh includes revenues under the floor price mechanism and revenues from contract settlements.

Equity income from Bruce A in 2013 was $351 million higher than 2012. The increase was mainly due to:

- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher incremental earnings from Unit 3 due to the West Shift Plus planned outage during first and second quarter 2012
- recognition in first quarter 2013 of an insurance recovery of approximately $40 million related to the May 2012 Unit 2 electrical generator failure that impacted Bruce A in 2012 and 2013
- higher incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013.

Equity income from Bruce B in 2013 was $55 million lower than 2012. The decrease was mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

In 2012, equity income from Bruce A was $182 million lower than 2011. The decrease was mainly due to lower volumes and higher operating costs resulting from the Unit 4 and the Unit 3 West Shift Plus planned outages, partially offset by incremental earnings from Units 1 and 2 which returned to service in October 2012.

In 2012, equity income from Bruce B was $86 million higher than 2011. The increase was mainly due to higher volumes and lower operating costs resulting from fewer outage days, lower lease expense and higher realized prices.

The overall plant availability percentages in 2014 are expected to be high 80s for both Bruce A and Bruce B. Planned maintenance on a Bruce A unit is scheduled to occur in first half of 2014. Planned maintenance on two Bruce B units is scheduled to occur in first and fourth quarters of 2014.

U.S. Power

We own approximately 3,800 MW of power generation capacity in New York and New England, including plants powered by natural gas, oil, hydro and wind.

We earn revenues in both New York and New England in two ways – by providing capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. The energy markets compensate power providers for the actual energy they supply.

Providing capacity

Capacity revenues in New York and New England are a function of two factors – capacity prices and plant availability. It is important for us to keep our plant availability high to maximize the amount of capacity we get paid for.

Capacity prices paid to capacity suppliers in New York are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. The parameters are determined for each zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in the forecasted demand.

The price paid for capacity in the New England Power Pool is determined by annual competitive auctions which are held three years in advance of the applicable capacity year. Auction results are impacted by actual and projected power demand, power supply, and other factors.

Selling energy

We focus on selling power under short and long-term contracts to wholesale, commercial and industrial customers. In some cases, power sales are bundled with other energy services that we earn additional revenues for providing in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM).

We meet our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices.

U.S. Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information for more details.

year ended December 31 (millions of US$)	2013	2012	2011
Revenue			
Power[1]	**1,484**	1,189	1,139
Capacity	**295**	234	227
Other[2]	**56**	51	80
	1,835	1,474	1,446
Commodity purchases resold	**(1,003)**	(765)	(618)
Plant operating costs and other[2]	**(462)**	(452)	(514)
General, administrative and support costs	**(47)**	(48)	(41)
Comparable EBITDA	**323**	209	273
Comparable depreciation and amortization	**(107)**	(121)	(109)
Comparable EBIT	**216**	88	164

1 The realized gains and losses from financial derivatives used to buy and sell power, natural gas and fuel oil to manage U.S. Power's assets are presented on a net basis in power revenues.
2 Includes revenues and costs related to a third party service agreement at Ravenswood.

Sales volumes and plant availability

year ended December 31	2013	2012	2011
Physical sales volumes (GWh)			
Supply			
Generation	**6,173**	7,567	6,880
Purchased	**9,001**	9,408	6,018
	15,174	16,975	12,898
Plant availability[1]	**84%**	85%	87%

1 The percentage of time in a year the plant is available to generate power, regardless of whether it is running.

U.S. Power's comparable EBITDA in 2013 was US$114 million higher than 2012. This reflected the net effect of:

- higher realized capacity prices in New York
- higher realized power prices partially offset by the impact of higher fuel costs
- higher revenues and certain adjustments on sales to wholesale, commercial and industrial customers.

In 2012, U.S. Power's comparable EBITDA was US$64 million lower than 2011. This reflected the net effect of:

- lower realized power prices
- higher load serving costs and higher sales to wholesale, commercial and industrial customers
- increased generation at the Ravenswood facility offset by reduced water flows at the TC Hydro facilities.

Average New York Zone J spot capacity prices were approximately 38 per cent higher in 2013 than in 2012. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2013.

Commodity prices in U.S. Power were higher in 2013 as natural gas prices recovered from low levels in 2012. Higher natural gas prices, fuel transportation constraints in the northeast U.S. and severe weather in both winter 2012/13 and summer 2013 were factors that contributed to an average increase of Independent

System Operator (ISO) power prices in New England of approximately 55 per cent and New York City of approximately 33 per cent in 2013 compared to 2012.

Physical sales volumes in 2013 decreased compared to 2012. Generation volumes decreased primarily due to lower generation at the Ravenswood facility in fourth quarter 2013 compared to fourth quarter 2012, when Ravenswood ran at higher than normal generation levels during and following Superstorm Sandy when damage at several other power and transmission facilities reduced power supply in New York City. Purchased volumes were also lower in 2013 compared to 2012 as volumes purchased to serve the commercial and industrial customers in the New England market decreased offset by higher volumes in the PJM market.

Power revenue and commodity purchases resold were 25 per cent and 31 per cent higher, respectively, in 2013 compared to 2012 mainly due to the higher commodity prices mentioned above.

As at December 31, 2013, approximately 4,300 GWh or 53 per cent of U.S. Power's planned generation is contracted for 2014, and 1,800 GWh or 24 per cent for 2015. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage.

Natural Gas Storage

We own or control 156 Bcf of non-regulated natural gas storage capacity in Alberta. This includes contracts for long-term, Alberta-based storage capacity from a third party, which expire in 2030, subject to early termination rights in 2015. This business operates independently from our regulated natural gas transmission business and from ANR's regulated storage business, which are included in our Natural Gas Pipelines segment.

Storage capacity

year ended December 31, 2013	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta	68	550
Third-party storage	38	630
	156	1,905

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements.

The natural gas storage business is affected by the change in seasonal natural gas price spreads, which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons. We manage this exposure by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. We sell a portfolio of short, medium and long-term storage products to participants in the Alberta and interconnected gas markets.

Proprietary natural gas storage transactions include a forward purchase of natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to seasonal natural gas price spreads.

These forward natural gas contracts provide highly effective economic hedges but do not meet the specific criteria for hedge accounting and, therefore, are recorded at their fair value through net income based on the forward market prices for the contracted month of delivery. We record changes in the fair value of these contracts in revenues. We do not include changes in the fair value of natural gas forward purchase and sales contracts when we calculate comparable earnings, because they do not represent the amounts that will be realized on settlement.

Natural Gas Storage and other results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 15 for more information.

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Natural Gas Storage and other[1]	**73**	77	84
General, administrative and support costs	**(10)**	(10)	(6)
Comparable EBITDA	**63**	67	78
Comparable depreciation and amortization	**(12)**	(10)	(12)
Comparable EBIT	**51**	57	66

1 Includes our share of equity income from our investment in CrossAlta up to December 2012. In December 2012, we acquired the remaining 40 per cent interest in CrossAlta, bringing our ownership interest to 100 per cent and commenced consolidating their operations.

Comparable EBITDA in 2013 was $4 million lower than 2012, mainly due to lower realized natural gas storage price spreads, partially offset by incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

In 2012, comparable EBITDA was $11 million lower than 2011, mainly due to lower realized natural gas storage price spreads, partially offset by lower operating costs.

SIGNIFICANT EVENTS

Canadian Power

Ontario Solar

In late 2011, we agreed to buy nine Ontario solar generation facilities (combined capacity of 86 MW) from Canadian Solar Solutions Inc., for approximately $500 million. We completed the acquisition of the first facility for $55 million in June 2013, two additional facilities in September 2013 for $99 million, and a fourth facility in December 2013 for $62 million. We expect the acquisition of the remaining five facilities to close in 2014, subject to satisfactory completion of the related construction activities and regulatory approvals. All power produced by the solar facilities is currently or will be sold under 20-year PPAs with the OPA.

Cancarb Limited and Cancarb Waste Heat Facility

On January 20, 2014 we announced we had reached an agreement for the sale of Cancarb Limited, our thermal carbon black facility, and its related power generation facility for $190 million subject to closing adjustments. The sale is expected to close in late first quarter 2014.

Bécancour

In June 2013, Hydro-Québec notified us that it would exercise its option to extend the agreement to suspend all electricity generation from the Bécancour power plant through 2014. In December 2013, we entered into an amendment to the original suspension agreement with Hydro-Québec to further extend suspension of generation through to the end of 2017. Under the amendment, Hydro-Québec continues to have the option (subject to certain conditions) to further extend the suspension past 2017. The amendment also includes revised provisions intended to reduce Hydro-Québec's payments to us for Bécancour's natural gas transportation costs during the suspension period, although we retain our ability to recover our full capacity costs under the Electricity Supply Contract with Hydro-Québec while the facility is suspended. Final execution of this amendment is conditional on the pending approval by the Régie de l'énergie.

Sundance A

Sundance A Unit 1 returned to service in September 2013 and Sundance A Unit 2 returned to service in October 2013 following an outage that began in December 2010. The operator was ordered by an arbitration panel in July 2012 to rebuild these units.

The revenues and costs recorded in first quarter 2012 from the Sundance A PPA were offset by a second quarter 2012 charge recorded as a result of the July 2012 Sundance A arbitration decision, which determined that the units were in force majeure effective November 2011. We recorded the $50 million charge to second quarter 2012 earnings, of which $20 million related to amounts accrued in 2011. Throughout 2011, revenues and costs had been recorded as though the outages were interruptions of supply in accordance with the terms of the PPA.

Bruce Power

In April 2013, Bruce Power announced that it had reached an agreement with the OPA to extend the Bruce B floor price through to the end of the decade, which is expected to coincide with the 2019 and 2020 end of life dates for the Bruce B units.

Bruce Power returned Bruce A Unit 4 to service in April 2013 after completing an expanded life extension outage investment program, which began in August 2012. It is anticipated that this investment will allow Unit 4 to operate until at least 2021.

On January 31, 2014, Cameco Corporation (Cameco) announced it had agreed to sell its 31.6 per cent limited partnership interest in Bruce B to BPC Generation Infrastructure Trust (BPC). We are considering our option to increase our Bruce B ownership percentage.

Napanee

In December 2012, we signed a contract with the OPA to develop, own and operate a new 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. The project is on schedule and we expect to complete the permitting process in late 2014. We expect to invest approximately $1.0 billion in the Napanee facility during construction and commercial operations are expected to begin in late 2017 or early 2018.

U.S. Power

Capacity prices in the New York market are established through a series of forward auctions and utilize a demand curve administered price for purposes of setting the monthly spot price. The demand curve, among other inputs, uses assumptions with respect to the expected cost of the most likely peaking generation technology applicable to new entrants to the market. In January 2014, the FERC accepted a new rate for the demand curve that was filed by New York ISO as part of its triennial Demand Curve Reset (DCR) process. The filing changed the generation technology used in the DCR versus that used during the last reset process for New York City Zone J where Ravenswood operates. We do not expect this change to impact Zone J capacity prices in 2014, however, this new assumption does have the potential to negatively affect these capacity prices in 2015 and 2016.

Additionally, another recent FERC decision affecting future capacity auctions in New England Power Pool (NEPOOL) may potentially improve capacity price conditions in 2018 and beyond for our assets that are located in NEPOOL.

BUSINESS RISKS

The following are risks specific to our energy business. See page 76 for information about general risks that affect the company as a whole.

Fluctuating power and natural gas market prices

Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta, and in our U.S. Power operations in New England and New York, are exposed to commodity price volatility. Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions and the price of natural gas, as power prices are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on power prices and therefore earnings from these facilities. Our Coolidge Generating Station and our portfolio of assets in Eastern Canada are fully contracted, and are therefore not subject to fluctuating commodity prices. Bruce Power's exposure to fluctuating power prices is discussed further below.

To mitigate the impact of power price volatility in Alberta and the U.S. northeast, we sell a portion of our supply under medium to long-term sales contracts where contract terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if unexpected plant outages occur. This unsold supply is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Under an agreement with the OPA, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's non-contracted volumes are subject to spot price volatility. When spot prices are below the floor price, Bruce B receives the floor price for all of its output. Bruce B also enters into third party fixed-price contracts where it receives the difference between the contract price and spot price. All Bruce A output is sold into the Ontario wholesale power spot market under a fixed-price contract with the OPA.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

U.S. Power capacity payments

A significant portion of revenues earned by Ravenswood and a portion of revenues earned by our power facilities in New England are driven by capacity payments. Fluctuations in capacity prices can have a material impact on these businesses, particularly in New York. New York capacity prices are determined by a series of voluntary forward auctions and a mandatory spot auction. The forward auctions are bid based while the mandatory spot auction is affected by a demand curve price setting process that is driven by a number of established parameters that are subject to periodic review by the New York ISO and FERC. These parameters are determined for each capacity zone and include the forecasted cost of a new unit entering the market, available existing operable supply and fluctuations in forecasted demand. Capacity payments are also a function of plant availability which is discussed below.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

For facilities we do not operate, our purchase agreements include a financial remedy if a plant owner does not deliver as agreed. The Sundance and Sheerness PPAs, for example, require the producers to pay us market-based penalties if they cannot supply the amount of power we have agreed to purchase.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity. These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability.

Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply.

Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets.

Hydrology

Our hydroelectric power generation facilities in the northeastern U.S. are subject to potential hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Execution, capital cost and permitting

Energy's construction programs are subject to execution, capital cost and permitting risks.

Corporate

OTHER INCOME STATEMENT ITEMS

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Comparable interest expense	**984**	976	939
Comparable interest income and other	**(42)**	(86)	(60)
Comparable income tax	**662**	477	594
Net income attributable to non-controlling interests	**125**	118	129
Preferred share dividends	**74**	55	55

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Comparable interest on long-term debt (including interest on junior subordinated notes)			
Canadian dollar-denominated	**495**	513	490
U.S. dollar-denominated	**766**	740	734
Foreign exchange	**20**	-	(7)
	1,281	1,253	1,217
Other interest and amortization expense	**(10)**	23	24
Capitalized interest	**(287)**	(300)	(302)
Comparable interest expense	**984**	976	939

Comparable interest expense this year was $8 million higher compared to 2012 because of incremental interest on long term debt issues of:

- US$1.25 billion in October 2013
- US$500 million in July 2013
- $750 million in July 2013
- US$500 million in July 2013 by TC PipeLines, LP
- US$750 million in January 2013
- US$1.0 billion in August 2012

as well as higher foreign exchange on interest expense related to U.S. dollar denominated debt, partially offset by Canadian and U.S. dollar denominated debt maturities. In addition, there was a decrease in capitalized interest due to Bruce Units 1 and 2 being placed in service in 2012, partially offset by increased capitalized interest on the Gulf Coast project.

Comparable interest expense in 2012 was $37 million higher than 2011 because of incremental interest on debt issues of:

- US$1.0 billion in August 2012
- US$500 million in March 2012
- $750 million in November 2011
- US$350 million in June 2011 by TC PipeLines, LP.

These increases also reflected the negative impact of a stronger U.S. dollar on U.S. dollar-denominated interest.

Comparable interest income and other was $44 million lower compared to 2012. This decrease was mainly because of losses in 2013 compared to gains in 2012 on the settlement of derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital balances. In 2012, comparable interest income and other was $26 million higher than 2011 because of higher gains in 2012 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income and on translation of foreign denominated working capital.

Comparable income tax increased $185 million in 2013 compared to 2012 mainly because of higher pre-tax earnings in 2013 compared to 2012 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions. In 2012, comparable income tax decreased $117 million from 2011 because of lower pre-tax earnings.

Net income attributable to non-controlling interests increased in 2013 compared to 2012 primarily due to the sale of a 45 per cent interest in each of GTN LLC and Bison to TC PipeLines, LP in July 2013.

Net income attributable to non-controlling interests decreased in 2012 compared to 2011 because of lower earnings in TC PipeLines, LP mainly due to lower earnings from Great Lakes, partially offset by a full year of earnings from GTN and Bison.

Preferred share dividends increased $19 million in 2013 compared to 2012 because of the issuance of the Series 7 preferred shares in March 2013.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of an economic cycle, and rely on our operating cash flows to sustain our business, pay dividends and fund a portion of our growth.

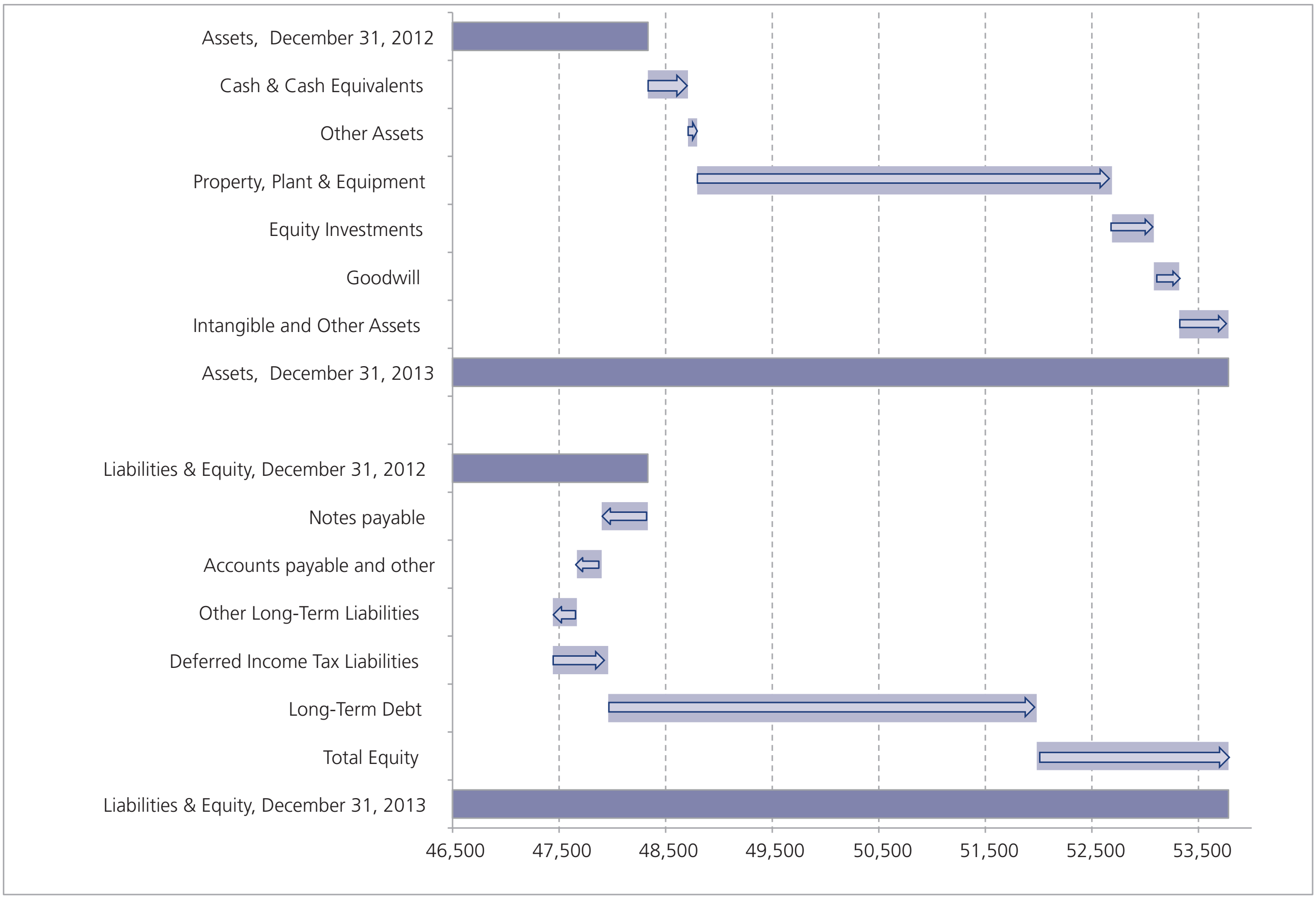
We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets, cash on hand and substantial committed credit facilities.

We access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

Balance sheet analysis

As of December 31, 2013, total assets increased $5.5 billion, total liabilities increased $3.7 billion and total equity rose $1.8 billion compared to December 31, 2012.

The increase in assets is primarily due to increases in property, plant and equipment, intangible and other assets, and equity investments. Property, plant and equipment increased by $3.9 billion primarily due to the construction of the Gulf Coast project, expansion of our Mexican pipelines projects and further investment in the NGTL System. Intangible and other assets rose by $0.5 billion due to the increase in our capital projects under development. Equity investments increased by $0.4 billion primarily due to an increase in our investment in Bruce B.



Capital structure

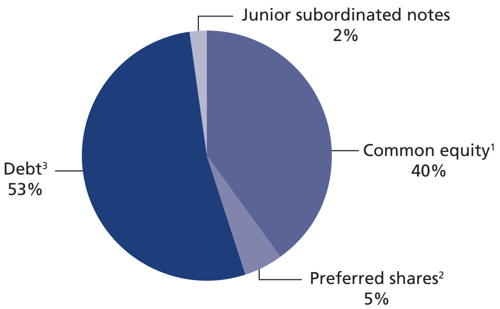
at December 31 (millions of $)	2013	2012
Notes payable	**1,842**	2,275
Long-term debt	**22,865**	18,913
Junior subordinated notes	**1,063**	994
Cash and cash equivalents	**(927)**	(551)
Debt, net of cash and cash equivalents	**24,843**	21,631
Equity – controlling interests	**18,525**	16,911
Equity – non-controlling interests	**1,611**	1,425
Total equity	**20,136**	18,336
	44,979	39,967

In 2013, we issued $4.3 billion and repaid $1.3 billion of long term debt. The strengthening of the U.S. dollar also contributed a $1 billion increase on translation of our U.S. dollar-denominated debt. In 2013, notes payable decreased by $0.4 billion and cash and cash equivalents increased by $0.4 billion.

Total equity increased $1.8 billion in 2013 mainly due to an increase in retained earnings, a $600 million preferred share issuance and a $400 million common unit issuance by TC PipeLines, LP.

Consolidated capital structure

at December 31, 2013



1 Includes non-controlling interests in TC PipeLines, LP and Portland
2 Includes preferred shares of TCPL
3 Net of cash and excluding junior subordinated notes

The following table shows how we have financed our business activities over the last three years. We continue to fund our extensive capital program through cash flow from operations supplemented by capital market financing activity.

year ended December 31 (millions of $)	2013	2012	2011
Net cash provided by operations	**3,674**	3,571	3,686
Net cash used in investing activities	**(5,120)**	(3,256)	(3,054)
(Deficiency)/surplus	**(1,446)**	315	632
Net cash provided by/(used in) financing activities	**1,794**	(403)	(642)
	348	(88)	(10)

Liquidity will continue to be comprised of predictable cash flow generated from operations, committed credit facilities, our ability to access debt and equity markets in both Canada and the U.S., and portfolio management including additional drop downs of assets into TC PipeLines, LP.

As at December 31, 2013, we were in compliance with all of our financial covenants. Provisions of various trust indentures and credit arrangements that certain of our subsidiaries are party to restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Net cash provided by operations

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Funds generated from operations	**4,000**	3,284	3,451
(Increase)/decrease in operating working capital	**(326)**	287	235
Net cash provided by operations	**3,674**	3,571	3,686

Funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations, excluding the timing effects of working capital changes. See page 15 for more information about non-GAAP measures.

At December 31, 2013, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $2.2 billion. This short-term deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to North American capital markets
- approximately $5 billion of unutilized committed revolving bank lines.

Net cash used in investing activities

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Capital expenditures	**4,461**	2,595	2,513
Other investing activities	**659**	661	541

Our 2013 capital expenditures were incurred primarily for construction of the Gulf Coast project, expanding our NGTL System and construction of our Mexican pipelines. Other investing activities in 2013 included the acquisitions of four solar facilities from Canadian Solar Solutions Inc.

We are developing quality projects under our long-term $38 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements and once completed, are expected to generate significant growth in earnings and cashflow.

Our $38 billion capital program is comprised of $12 billion of small to medium-sized projects and $26 billion of large scale projects each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow and a combination of funding options including:

- senior debt
- preferred shares
- hybrid securities
- portfolio management including additional drop downs to TC PipeLines, LP or asset sales
- potential involvement of strategic or financial partners.

Additional financing alternatives available include common equity through DRP or lastly, discrete equity issuances.

Net cash provided by/(used in) financing activities

year ended December 31 (millions of $)	**2013**	**2012**	**2011**
Long-term debt issued, net of issue costs	**4,253**	1,491	1,622
Long-term debt repaid	**(1,286)**	(980)	(1,272)
Notes payable (repaid)/issued, net	**(492)**	449	(224)
Dividends and distributions paid	**(1,522)**	(1,416)	(1,147)
Common shares issued	**72**	53	58
Preferred shares issued, net of issue costs	**585**	-	-
Partnership units of subsidiary issued, net of issue costs	**384**	-	321
Preferred shares of subsidiary redeemed	**(200)**	-	-

Long-term debt issued:

- US$750 million of senior unsecured notes, maturing on January 15, 2016 and bearing interest at 0.75 per cent per annum, in January 2013
- US$500 million of three-year London Interbank Offered Rate-based floating rate notes maturing on June 30, 2016, bearing interest at an initial annual rate of 0.95 per cent, in July 2013
- $450 million of ten-year medium term notes maturing on July 19, 2023, bearing interest at 3.69 per cent per annum, in July 2013
- $300 million of 30-year medium term notes maturing November 15, 2041, bearing interest at 4.55 per cent per annum, in July 2013
- US$625 million of senior unsecured notes, maturing on October 16, 2023 and bearing interest at 3.75 per cent per annum, in October 2013
- US$625 million of senior unsecured notes, maturing on October 16, 2043 and bearing interest at 5.0 per cent per annum, in October 2013.

Long-term debt retired:

- US$350 million of 4.00 per cent senior unsecured notes, in June 2013
- US$500 million of 5.05 per cent senior unsecured notes, in August 2013.

In March 2013, we completed a public offering of 24 million Series 7 cumulative redeemable first preferred shares at a price of $25 per share for aggregate gross proceeds of $600 million. Investors will be entitled to receive fixed cumulative dividends at an annual rate of $1.00 per share, payable quarterly. Investors will have the right to convert their shares into cumulative redeemable first preferred shares, Series 8, every fifth year beginning on April 30, 2019. The holders of Series 8 shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate plus 2.38 per cent.

In October 2013, we redeemed four million outstanding 5.60 per cent Cumulative Redeemable First Preferred Shares Series U of TCPL. The Series U Shares were redeemed at a price of $50 per share plus $0.5907 of accrued and unpaid dividends. The total face value of the outstanding Series U Shares was $200 million and carried an aggregate of $11 million in annualized dividends.

In January 2014, we completed a public offering of Series 9 preferred shares for gross proceeds of $450 million, reducing the capacity under our equity shelf prospectus to $1.55 billion. Investors will be entitled to receive fixed cumulative dividends at an annual rate of $1.0625 per share, payable quarterly. Investors will have the right to convert their shares into cumulative redeemable first preferred shares, Series 10, every fifth year beginning on October 30, 2019. The holders of Series 10 shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the then 90-day Government of Canada treasury bill rate plus 2.35 per cent.

In January 2014, we announced the redemption of Series Y preferred shares of TCPL at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y Shares was $200 million and carried an aggregate of $11 million in annualized dividends.

The net proceeds of the above offerings were used for general corporate purposes and to reduce short-term indebtedness.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at US$43.85 per common unit for gross proceeds of US$388 million. We contributed an additional approximate US$8 million to maintain our general partnership interest and did not purchase any other units. Upon completion of this offering, our ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent.

In July 2013, TC PipeLines, LP entered into a five-year, US$500 million medium-term loan, maturing July 2018. The proceeds from the public offering, term loan and partner contribution were used to finance the acquisition of the 45 per cent interest in GTN and Bison from us.

As at December 31, 2013, we had unused capacity of $2.0 billion, $2.0 billion and US$4.0 billion under our equity, Canadian debt and U.S. debt shelf prospectuses to facilitate future access to the North American debt and equity markets.

Credit facilities

We have committed, revolving credit facilities to primarily support our commercial paper programs. The commercial paper programs, along with additional demand credit facilities are used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At December 31, 2013, we had $6.2 billion (2012 – $5.3 billion) in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	For	Matures
$3.0 billion	$3.0 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2018
US$1.0 billion	US$0.8 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, syndicated, revolving extendible credit facility that is used for TCPL USA general corporate purposes	November 2014
US$1.0 billion	US$1.0 billion	TransCanada American Investments Ltd. (TAIL)	Committed, syndicated, revolving, extendible credit facility that supports the TAIL U.S. dollar commercial paper program in the U.S.	November 2014
$1.1 billion	$0.3 billion	TCPL / TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At December 31, 2013, we had outstanding $0.7 billion in letters of credit under these lines	Demand

At December 31, 2013, our operated affiliates had $0.3 billion of undrawn capacity on committed credit facilities.

Contractual obligations

Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	1,842	1,842	-	-	-
Long-term debt (includes junior subordinated notes)	23,928	973	3,751	2,494	16,710
Operating leases (future annual payments for various premises, services and equipment, less sub-lease receipts)	752	90	177	160	325
Purchase obligations	8,187	3,134	2,914	1,068	1,071
Other long-term liabilities reflected on the balance sheet	386	8	16	18	344
	35,095	6,047	6,858	3,740	18,450

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Long-term debt

At the end of 2013, we had $22.9 billion of long-term debt and $1.1 billion of junior subordinated notes, compared to $18.9 billion of long-term debt and $1.0 billion of junior subordinated notes at December 31, 2012.

Total notes payable were $1.8 billion at the end of 2013 compared to $2.3 billion at the end of 2012.

We attempt to spread out the maturity profile of our debt. The majority of our obligations mature beyond five years with an average term of 12 years.

At December 31, 2013, scheduled principal repayments and interest payments related to long-term debt were as follows:

Principal repayments

Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	1,842	1,842	-	-	-
Long-term debt	22,865	973	3,751	2,494	15,647
Junior subordinated notes	1,063	-	-	-	1,063
	25,770	2,815	3,751	2,494	16,710

Interest payments

Payments due (by period)

at December 31, 2013 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Long-term debt	16,798	1,254	2,315	2,111	11,118
Junior subordinated notes	3,614	68	135	135	3,276
	20,412	1,322	2,450	2,246	14,394

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 10 years.

Our commitments under the Alberta PPAs are considered operating leases. Future payments under these PPAs depend on plant availability, so we do not include them in our summary of future obligations. Our share of power purchased under the PPAs in 2013 was $242 million (2012 – $238 million; 2011 – $309 million).

We have subleased a part of the PPAs to third parties under terms and conditions similar to our own leases.

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include signed contracts related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)

(not including pension plan contributions)

at December 31, 2013 (millions of $)	**Total**	**less than 12 months**	**12 - 36 months**	**37 - 60 months**	**more than 60 months**
Natural Gas Pipelines					
Transportation by others[1]	463	134	173	133	23
Capital expenditures[2,3]	1,252	845	407	-	-
Other	13	7	4	2	-
Oil Pipelines					
Capital expenditures[2,4]	2,537	1,223	1,188	126	-
Other	70	7	14	14	35
Energy					
Commodity purchases[5]	2,568	496	929	655	488
Capital expenditures[2,6]	120	47	60	13	-
Other[7]	1,140	353	137	125	525
Corporate					
Information technology and other	24	22	2	-	-
	8,187	3,134	2,914	1,068	1,071

1 Rates are primarily based on known 2013 levels. Demand rates may change after 2013. Purchase obligations are based on known or contracted demand volumes only and do not include commodity charges incurred when volumes flow.

2 Amounts are estimates and can vary depending on timing of construction and project enhancements. We expect to fund capital projects with cash from operations, by issuing senior debt and subordinated capital, if required, and through portfolio management.

3 Primarily relate to the construction costs of the NGTL System expansion and the Mexican pipeline projects.

4 Primarily relate to Keystone XL and Grand Rapids.

5 Includes fixed and variable components but does not include derivatives. The variable components are estimates and can vary depending on plant production, market prices and regulatory tariffs.

6 Primarily relate to preliminary construction and development costs of Napanee.

7 Includes estimates of certain amounts that may change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries and changes in regulated rates for transportation. This also includes the remaining purchase obligations for Ontario Solar.

KEY PURCHASE COMMITMENTS

Ontario Solar

In December 2011, we announced an agreement to purchase nine solar facilities in Ontario with a combined capacity of 86 MW at a cost of approximately $500 million. To date, we have purchased four of the nine solar facilities at a cost of $216 million, with the expectation to acquire the remaining facilities in 2014.

GUARANTEES

Bruce Power

We and our partners, Cameco and BPC, have severally guaranteed one-third of some of Bruce B's contingent financial obligations related to power sales agreements, a lease agreement and contractor services. The Bruce B guarantees have terms to 2018 except for one guarantee with no termination date that has no exposure associated with it.

We and BPC have each severally guaranteed half of certain contingent financial obligations of Bruce A related to a sublease agreement, an agreement with the OPA to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019.

At December 31, 2013, our share of the potential exposure under the Bruce A and B guarantees was estimated to be $629 million. The carrying amount of these guarantees was estimated to be $8 million. Our exposure under certain of these guarantees is unlimited.

Other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) the financial performance of these entities relating mainly to redelivery of natural gas, PPA payments and the payment of liabilities. The guarantees have terms ranging from 2014 to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2013 to be a maximum of $51 million. The carrying amount of these guarantees was $10 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2014, we expect to make funding contributions of approximately $70 million for the defined benefit pension plans, approximately $6 million for the other post-retirement benefit plans and approximately $34 million for the savings plan and defined contribution pension plans. We also expect to provide a $47 million letter of credit to our Canadian defined benefit plan in lieu of cash funding.

In 2013, we made funding contributions of $79 million to our defined benefit pension plans, $6 million for the other post-retirement benefit plans and $29 million for the savings plan and defined contribution pension plans. We also provided a $59 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2015. Based on current market conditions, we expect funding requirements for these plans to approximate 2013 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans increased to $134 million in 2013 from $99 million, mainly due to a lower discount rate used to measure the benefit obligation.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, including making sure there are appropriate management systems in place to manage our risks, and adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Business interruption
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events, could decrease revenues, increase costs or result in legal or other expenses, all of which could reduce our earnings. We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances. Losses that are not covered by insurance may have an adverse effect on our operations, earnings, cash flow and financial position.

Our reputation and relationships
Stakeholders, such as Aboriginal communities, other communities, landowners, governments and government agencies, and environmental non-governmental organizations can have a significant impact on our operations, infrastructure development and overall reputation. Our Stakeholder Engagement Framework – which we have implemented across the company – is our formal commitment to stakeholder engagement. Our four core values – integrity, collaboration, responsibility and innovation – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders.

Execution and capital costs
Investing in large infrastructure projects involves substantial capital commitments, based on the assumption that these assets will deliver an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers, in exchange for the potential benefit they will realize when the project is finished. While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun risk which may decrease our return on these projects.

Cyber security
Security threats, including cyber security threats, and related disruptions can have a negative impact on our business. We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and

functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.

Pipeline abandonment costs

The NEB's Land Matters Consultation Initiative (LMCI) is an initiative that will require all Canadian pipeline companies regulated by the NEB to set aside funds to cover future abandonment costs.

The NEB provided several key guiding principles during the LMCI process, including the position that abandonment costs are a legitimate cost of providing pipeline service and are recoverable, upon NEB approval, from users of the individual pipeline systems. The first hearing addressing the basis and the approach to the determination of specific pipeline abandonment cost estimates was held in October 2012. Additional hearings and the Board's decisions are scheduled to be completed by June 2014. We do not expect the collection of funds to begin until 2015 at the earliest.

Health, safety and environment

Our approach to managing health and safety and protecting the environment is guided by our HSE commitment statement, which outlines guiding principles for a safe and healthy environment for our employees, contractors and the public, and expresses our commitment to protect the environment.

We are committed to continually improving our occupational health and safety performance, and to promoting safety on and off the job, in the belief that all occupational injuries and illnesses are preventable. We strive to work with companies and contractors who share our commitment and approach. We also have environmental controls in place, including physical design, programs, procedures and processes, to help manage the environmental risk factors we are exposed to, including spills and releases.

Management monitors HSE performance and is kept informed about operational issues and initiatives through formal incident and issues management processes and regular reporting.

The safety and integrity of our existing and newly-developed infrastructure is also a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought in service only after all necessary requirements have been satisfied. We spent $376 million in 2013 for pipeline integrity on the pipelines we operate, an increase of $67 million over 2012 primarily due to increased levels of in-line pipeline inspection on all systems as well an increased amount of pipe replacement required due to population encroachment on the pipelines. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures have minimal impact on our earnings. Under the Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures have no impact on our earnings. Our safety record in 2013 continued to exceed industry benchmarks.

Spending associated with public safety on Energy assets is focused primarily on our hydro dams and associated equipment.

Our main environmental risks are:

- air and greenhouse gas (GHG) emissions
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- compliance with corporate and regulatory policies and requirements.

As described in the Business interruption section, above, we have a set of procedures in place to manage our response to natural disasters and other catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in the Operating Procedures in our Incident Management System, are designed to help protect the health and safety of our employees, minimize risk to the public and limit the impact any operational issues caused by a natural disaster might have on the environment.

Environmental compliance and liabilities

Our facilities are subject to stringent federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges and waste management. Our facilities are required to obtain and comply with a wide variety of environmental registrations, licences, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders for future operations.

We continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

It is not possible to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) can change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2013, we had accrued approximately $32 million related to these obligations ($37 million at the end of 2012). This represents the amount that we have estimated that we will need to manage our currently known environmental liabilities. We believe that we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts. We adjust this reserve quarterly to account for changes in liabilities.

Greenhouse gas emissions regulation risk

We own assets and have business interests in a number of regions where there are regulations to address industrial GHG emissions. We have procedures in place to comply with these regulations, including:

- under the Specified Gas Emitters Regulation in Alberta, established industrial facilities with GHG emissions above a certain threshold have had to reduce their emissions by 12 per cent below an average intensity baseline since 2007. Our NGTL System facilities and Sundance and Sheerness are subject to this regulation. We recover compliance costs on the NGTL System through the tolls our customers pay. A portion of the compliance costs for Sundance and Sheerness are recovered through market pricing and contract flow through provisions. We recorded $25 million for the Alberta Specified Gas Emitters Regulation in 2013 (2012 – $15 million)
- B.C. has imposed a tax on carbon dioxide (CO_2) emissions from fossil fuel combustion since 2008. We recover the compliance costs for our compressor and meter stations through the tolls our customers pay. In 2013, we recorded $6 million (2012 – $5 million) for the B.C. carbon tax

- Northeastern U.S. states that are members of the Regional Greenhouse Gas Initiative (RGGI) implemented a CO_2 cap-and-trade program for electricity generators beginning January 2009. This program applies to both the Ravenswood and Ocean State Power generation facilities. We recorded $6 million in 2013 (2012 – $3 million) to participate in quarterly auctions of allowances under RGGI
- Québec's *Regulation Respecting a Cap-and-Trade System for Greenhouse Gas Emission Allowances* came into force in December 2011 with significant amendments finalized on December 2012. Beginning in January 2013, Bécancour was required to cover its GHG emissions. As per the regulations, the government awarded free emission units for the majority of Bécancour's compliance requirements for 2013. The remaining were purchased through an auction. The pipeline facilities in Québec are also covered under this regulation and have purchased compliance instruments. We recorded less than $1 million for compliance with this regulation
- in 2013, California implemented a cap and trade program that impacts electricity importers as well as a number of industrial emitters of GHG emissions. Our costs associated with the program were less than $1 million.

There are federal, regional, state and provincial initiatives currently in development. While economic events may continue to affect the scope and timing of new regulations, we anticipate that most of our facilities will be subject to future regulations to manage industrial GHG emissions.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in large infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold.

We use derivative contracts to assist in managing our exposure to market risk, including:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- options – agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

We assess contracts we use to manage market risk to determine whether all, or a portion of it, meets the definition of a derivative.

Commodity price risk

We are exposed to changes in commodity prices, especially electricity and natural gas, which may affect our earnings. We use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

Foreign exchange and interest rate risk

Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, our exposure to changes in currency rates increases. Some of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk. We manage this using a combination of interest rate swaps and options.

Average exchange rate – U.S. to Canadian dollars

2013	1.03
2012	1.00
2011	0.99

The impact of changes in the value of the U.S. dollar on our U.S. operations is significantly offset by other U.S. dollar-denominated items, as set out in the table below. Comparable EBIT is a non-GAAP measure. See page 15 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2013**	**2012**	**2011**
U.S. and International Natural Gas Pipelines comparable EBIT	**542**	660	761
U.S. Oil Pipelines comparable EBIT	**389**	363	301
U.S. Power comparable EBIT	**216**	88	164
Interest on U.S. dollar-denominated long-term debt	**(766)**	(740)	(734)
Capitalized interest on U.S. dollar-denominated capital expenditures	**219**	124	116
U.S. non-controlling interests and other	**(196)**	(192)	(192)
	404	303	416

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

Derivatives designated as a net investment hedge

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

at December 31 (millions of $)	2013 Fair value[1]	2013 Notional or principal amount	2012 Fair value[1]	2012 Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2014 to 2019)[2]	**(201)**	**US 3,800**	82	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2014)	**(11)**	**US 850**	-	US 250
	(212)	**US 4,650**	82	US 4,050

1 Fair values equal carrying values.

2 Consolidated net income in 2013 included net realized gains of $29 million (2012 – gains of $30 million) related to the interest component of cross-currency swap settlements.

U.S. dollar-denominated debt designated as a net investment hedge

at December 31 (millions of $)	2013	2012
Carrying value	**14,200 (US 13,400)**	11,100 (US 11,200)
Fair value	**16,000 (US 15,000)**	14,300 (US 14,400)

The balance sheet classification of the fair value of derivatives used to hedge our U.S. dollar net investment in foreign operations is as follows:

at December 31 (millions of $)	2013	2012
Other current assets	**5**	71
Intangible and other assets	**-**	47
Accounts payable and other	**(50)**	(6)
Other long-term liabilities	**(167)**	(30)
	(212)	82

Counterparty credit risk

We have exposure to counterparty credit risk in the following areas:

- accounts receivable
- portfolio investments
- the fair value of derivative assets
- notes receivable.

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts

- using contract netting arrangements and obtaining financial assurances, such as guarantees and letters of credit or cash, when we believe it is necessary.

There is no guarantee, however, these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2013 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $240 million at December 31, 2013 with one counterparty ($259 million in 2012). This amount is secured by a guarantee from the counterparty's parent company and we anticipate collecting the full amount.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 month period and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

See page 67 for more information about our financial condition.

Dealing with legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position, results of operations or liquidity. We are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position, results of operations or liquidity.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

We carried out an evaluation under the supervision and with the participation of management, including our President and CEO and our CFO, of the effectiveness of our disclosure controls and procedures as at December 31, 2013 as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2013 based on the criteria described in "Internal Control – Integrated Framework" issued in

1992 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2013, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2013 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included herein.

Limitations of the effectiveness of controls

Management's assessment included an evaluation of the design and testing of the operational effectiveness of internal control over financial reporting. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Changes in internal control over financial reporting

There has been no change in our internal control over financial reporting that occurred during the year ended December 31, 2013, that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Effective January 1, 2014, management implemented an Enterprise Resource Planning (ERP) system, which had no impact on our internal control over financial reporting at December 31, 2013. As a result of the ERP system, certain processes supporting our internal control over financial reporting are expected to change in 2014. Management will continue to monitor these processes going forward.

CEO AND CFO CERTIFICATIONS

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2013 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements.

Rate-regulated accounting

Under GAAP, a company qualifies to use rate-regulated accounting (RRA) when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	**2013**	**2012**
Regulatory assets		
Long-term assets	**1,735**	1,629
Short-term assets (included in other current assets)	**42**	178
Regulatory liabilities		
Long-term liabilities	**229**	268
Short-term liabilities (included in accounts payable and other)	**7**	100

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value, and we calculate an impairment loss to recognize this.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit, including its goodwill, to its book value. If fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting units from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

- discount rates
- commodity and capacity prices
- market supply and demand assumptions
- growth opportunities
- output levels
- competition from other companies
- regulatory changes.

If our assumptions change significantly, our requirement to record an impairment charge could also change. There is a risk that adverse changes in key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. These assumptions could be negatively impacted by factors including changes in customer demand at Great Lakes for pipeline capacity and services, weather, levels of natural gas in storage, and regulatory decisions. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$266 million at December 31, 2013 (2012 – US$266 million).

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the asset retirement obligation (ARO) in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

Canadian regulated pipelines

The NEB's LMCI is an initiative for all pipeline companies regulated under the *National Energy Board Act* (Canada) to begin collecting and setting aside funds to cover future abandonment costs.

As part of the guidance provided by the initiative, the NEB has stated that abandonment costs are a legitimate cost of providing pipeline service and should be recoverable (with NEB approval) from system users.

In May 2009, the NEB established several filing deadlines for pipeline companies, including deadlines for

- estimating their pipeline abandonment costs
- proposing how they will collect these funds (through tolls or another satisfactory method)
- proposing how they will set aside the funds they collect.

We filed estimates for our regulated Canadian oil and natural gas pipelines in November 2011 as required. In February 2013, the NEB issued its Reasons for Decision regarding pipeline abandonment cost estimates. We filed revisions to our estimates in April 2013 and January 2014. In February and April 2013, we filed our set-aside and collection mechanism applications. An oral hearing to consider both applications commenced on January 14, 2014. Based on the NEB's direction in 2009, the earliest we could begin collecting funds through cost of service tolls would be 2015. The specific impacts on tolls will depend on the 2014 proceeding related to the collection mechanism.

FINANCIAL INSTRUMENTS

All financial instruments, including both derivative and non-derivative instruments, are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchases and normal sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of long-term debt has been estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data providers. The fair value of available for sale assets has been calculated using quoted market prices where available. Credit risk has been taken into consideration when calculating the fair value of non-derivative financial instruments.

Certain non-derivative financial instruments including cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity.

Contractual maturities of non-derivative liabilities

The following tables detail the remaining contractual maturities for our non-derivative financial liabilities, including both the principal and interest cash flows:

Contractual principal repayments of non-derivative financial liabilities

at December 31, 2013 (millions of $)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and thereafter**
Notes payable	1,842	1,842	-	-	-
Long-term debt	22,865	973	3,751	2,494	15,647
Junior subordinated notes	1,063	-	-	-	1,063
	25,770	2,815	3,751	2,494	16,710

Interest payments on non-derivative financial liabilities

at December 31, 2013 (millions of $)	**Total**	**2014**	**2015 and 2016**	**2017 and 2018**	**2019 and thereafter**
Long-term debt	16,798	1,254	2,315	2,111	11,118
Junior subordinated notes	3,614	68	135	135	3,276
	20,412	1,322	2,450	2,246	14,394

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify. The effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in other comprehensive income (OCI) in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

Derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk (held for trading). Changes in the fair value of held for trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held for trading derivative instruments can fluctuate significantly from period to period.

The recognition of gains and losses on the derivatives for the Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of power and natural gas derivatives have been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments is as follows:

at December 31 (millions of $)	**2013**	**2012**
Other current assets	**395**	259
Intangible and other assets	**112**	187
Accounts payable and other	**(357)**	(283)
Other long-term liabilities	**(255)**	(186)
	(105)	(23)

Anticipated timing of settlement – derivative instruments

The anticipated timing of settlement for derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2013 (millions of $)	**Total fair value**	**2014**	**2015 and 2016**	**2017 and 2018**
Derivative instruments held for trading				
Assets	346	268	74	4
Liabilities	(371)	(288)	(81)	(2)
Derivative instruments in hedging relationships				
Assets	161	128	33	-
Liabilities	(241)	(70)	(143)	(28)
	(105)	38	(117)	(26)

The effect of derivative instruments on the consolidated statement of income

The following summary does not include hedges of our net investment in foreign operations.

year ended December 31 (millions of $)	**2013**	**2012**
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Power	**19**	(30)
Natural gas	**17**	2
Foreign exchange	**(10)**	(1)
Amount of realized (losses)/gains in the year		
Power	**(49)**	5
Natural gas	**(13)**	(10)
Foreign exchange	**(9)**	26
Derivative instruments in hedging relationships[2,3]		
Amount of realized (losses)/gains in the year		
Power	**(19)**	(130)
Natural gas	**(2)**	(23)
Interest	**5**	7

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell power and natural gas are included net in energy revenues. Realized and unrealized gains and losses on interest rate and foreign exchange held for trading derivative instruments are included net in interest expense and interest income and other, respectively.

2 At December 31, 2013 all hedging relationships were designated as cash flow hedges except for interest rate derivative financial instruments designated as fair value hedges with a fair value of $5 million (2012 – $10 million) and a notional amount of US$200 million (2012 – US$350 million). In 2013, net realized gains on fair value hedges were $6 million (2012 – $7 million) and were included in interest expense. In 2013 and 2012, we did not record any amounts in net income related to ineffectiveness for fair value hedges.

3 The effective portion of the change in fair value of derivative instruments in hedging relationships is initially recognized in OCI and reclassified to energy revenues, interest expense and interest income and other, as appropriate, as the original hedged item settles. In 2013 and 2012, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of the Consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

year ended December 31 (millions of $, pre-tax)	2013	2012
Change in fair value of derivative instruments recognized in OCI (effective portion)		
Power	**117**	83
Natural Gas	**(1)**	(21)
Foreign Exchange	**5**	(1)
	121	61
Reclassification of gains on derivative instruments from AOCI to net income (effective portion)		
Power	**40**	147
Natural Gas	**4**	54
Interest	**16**	18
	60	219
Gains on derivative instruments recognized in earnings (ineffective portion)		
Power	**8**	7
	8	7

Credit risk related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2013, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $16 million (2012 – $37 million), with collateral provided in the normal course of business of nil (2012 – nil).

If the credit-risk-related contingent features in these agreements were triggered on December 31, 2013, we would have been required to provide additional collateral of $16 million (2012 – $37 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2013

Balance sheet offsetting/netting

Effective January 1, 2013, we adopted the Accounting Standards Update (ASU) on disclosures about balance sheet offsetting as issued by the Financial Accounting Standards Board (FASB) to enable readers to evaluate the effects of netting arrangements on our financial position. Adoption of the ASU has resulted in increased qualitative and quantitative disclosures about certain derivative instruments that are either offset in accordance with current GAAP or are subject to a master netting arrangement or similar agreement.

Accumulated other comprehensive income

Effective January 1, 2013, we adopted the ASU on reporting of amounts reclassified out of accumulated other comprehensive income (AOCI) as issued by the FASB. Adoption of the ASU has resulted in providing additional qualitative and quantitative disclosures about significant amounts reclassified out of AOCI into net income.

Future accounting changes

Obligations resulting from joint and several liability arrangements

In February 2013, the FASB issued guidance for recognizing, measuring, and disclosing obligations resulting from joint and several liability arrangements when the total amount of the obligation is fixed at the reporting date. Debt arrangements, other contractual obligations, and settled litigation and judicial rulings are examples of these obligations. This ASU is effective retrospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Foreign currency matters – cumulative translation adjustment

In March 2013, the FASB issued amended guidance related to the release of the cumulative translation adjustment into net income when a parent either sells a part or all of its investment in a foreign entity or no longer holds a controlling financial interest in a subsidiary or group of assets that is a business. This ASU is effective prospectively for fiscal years, and interim reporting periods within those years, beginning after December 15, 2013. Early adoption is allowed as of the beginning of the entity's fiscal year. We are evaluating the impact that adopting this ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

Unrecognized tax benefit

In July 2013, the FASB issued amended guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. This ASU is effective prospectively for fiscal years and interim reporting periods within those years, beginning after December 15, 2014. Early adoption is permitted. We are evaluating the impact that adopting the ASU would have on our consolidated financial statements, but do not expect it to have a material impact.

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2013	Fourth	Third	Second	First
Revenues	**2,332**	**2,204**	**2,009**	**2,252**
Net income attributable to common shares	**420**	**481**	**365**	**446**
Comparable earnings	**410**	**447**	**357**	**370**
Comparable earnings per share	**$0.58**	**$0.63**	**$0.51**	**$0.52**
Share statistics				
Net income per share – basic and diluted	**$0.59**	**$0.68**	**$0.52**	**$0.63**
Dividends declared per common share	**$0.46**	**$0.46**	**$0.46**	**$0.46**

2012	Fourth	Third	Second	First
Revenues	2,089	2,126	1,847	1,945
Net income attributable to common shares	306	369	272	352
Comparable earnings	318	349	300	363
Comparable earnings per share	$0.45	$0.50	$0.43	$0.52
Share statistics				
Net income per share – basic and diluted	$0.43	$0.52	$0.39	$0.50
Dividends declared per common share	$0.44	$0.44	$0.44	$0.44

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In Natural Gas Pipelines, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

In Oil Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income during any particular fiscal year remain relatively stable.

In Energy, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- market prices for natural gas and energy
- capacity prices and payments
- planned and unplanned plant outages
- acquisitions and divestitures
- certain fair value adjustments
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

Factors affecting financial information by quarter

We calculate 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 earnings exclude 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.

In second quarter 2013, comparable earnings excluded a $25 million favourable income tax adjustment due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax in June 2013.

In first quarter 2013, comparable earnings excluded $84 million of net income in 2013 related to 2012 from the NEB decision.

In second quarter 2012, comparable earnings excluded a $15 million after tax charge ($20 million pre-tax) from the Sundance A PPA arbitration decision.

FOURTH QUARTER 2013 HIGHLIGHTS

Reconciliation of non-GAAP measures

three months ended December 31 (unaudited) (millions of $, except per share amounts)	2013	2012
EBITDA	**1,320**	1,040
Non-comparable risk management activities affecting EBITDA	**(29)**	12
Comparable EBITDA	**1,291**	1,052
Comparable depreciation and amortization	**(396)**	(343)
Comparable EBIT	**895**	709
Other income statement items		
Comparable interest expense	**(240)**	(246)
Comparable interest income and other	**10**	20
Comparable income tax	**(198)**	(123)
Net income attributable to non-controlling interests	**(38)**	(28)
Preferred share dividends	**(19)**	(14)
Comparable earnings	**410**	318
Specific item (net of tax):		
Risk management activities[1]	**10**	(12)
Net income attributable to common shares	**420**	306
Comparable interest expense	**(240)**	(246)
Specific item:		
Risk management activities[1]	**-**	-
Interest expense	**(240)**	(246)
Comparable interest income and other	**10**	20
Specific item:		
Risk management activities[1]	**(9)**	(5)
Interest income and other	**1**	15
Comparable income tax expense	**(198)**	(123)
Specific item:		
Risk management activities[1]	**(10)**	5
Income tax expense	**(208)**	(118)
Comparable earnings per common share	**$0.58**	$0.45
Specific item (net of tax):		
Risk management activities[1]	**0.01**	(0.02)
Net income per common share	**$0.59**	$0.43

1

three months ended December 31 (unaudited) (millions of $)	2013	2012
Risk management activities gains/(losses):		
Canadian Power	**(2)**	(6)
U.S. Power	**36**	(5)
Natural Gas Storage	**(5)**	(1)
Foreign exchange	**(9)**	(5)
Income tax attributable to risk management activities	**(10)**	5
Total gains/(losses) from risk management activities	**10**	(12)

Comparable EBITDA and comparable EBIT by Business Segment

three months ended December 31, 2013 (unaudited) (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	**778**	**198**	**346**	**(31)**	**1,291**
Comparable depreciation and amortization	**(280)**	**(38)**	**(74)**	**(4)**	**(396)**
Comparable EBIT	**498**	**160**	**272**	**(35)**	**895**

three months ended December 31, 2012 (unaudited) (millions of $)	**Natural Gas Pipelines**	**Oil Pipelines**	**Energy**	**Corporate**	**Total**
Comparable EBITDA	690	172	222	(32)	1,052
Comparable depreciation and amortization	(236)	(36)	(68)	(3)	(343)
Comparable EBIT	454	136	154	(35)	709

Comparable earnings

Comparable earnings in fourth quarter 2013 were $92 million or $0.13 per share higher compared to the same period in 2012.

The increase in comparable earnings was primarily the result of:

- higher equity income from Bruce Power reflecting incremental earnings from Unit 4 due to fewer planned outage days and return to service of Units 1 and 2
- higher earnings from the Canadian Mainline due to the higher ROE of 11.50 per cent in 2013 compared to 8.08 per cent in 2012 due to the NEB decision
- higher earnings from the NGTL System because of a higher average investment base associated with 2012 and 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013 which included a higher ROE and incentive earnings
- higher earnings from the Keystone Pipeline System primarily due to higher volumes.

These increases were partly offset by:

- lower contribution from U.S. natural gas pipelines due to lower transportation revenue at ANR as well as reduced earnings from GTN and Bison due to the reduction of our effective ownership from 83 per cent to 50 per cent, beginning in July 2013
- lower earnings from Western Power primarily due to lower realized power prices.

Net income attributable to common shares

Our net income attributable to common shares was $420 million or $0.59 per share in fourth quarter 2013 compared to $306 million or $0.43 per share for the same period in 2012.

Highlights by business segment

Natural Gas Pipelines

Natural Gas Pipelines comparable EBIT increased $44 million for the three months ended December 31, 2013 compared to the same period in 2012 because of higher earnings from the Canadian Mainline due to the NEB decision in March 2013 and higher earnings from the NGTL System because of a higher average investment base associated with 2013 capital expenditures and the impact of the 2013-2014 NGTL Settlement which included a higher ROE of 10.10 per cent on 40 per cent deemed common equity. These increases were partially offset by lower contributions from GTN and Bison due to reduced effective ownership and lower revenue and higher OM&A costs at ANR.

Natural Gas Pipelines comparable depreciation and amortization increased by $44 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to a 2013 true-up for the higher composite depreciation rate in the 2013-2014 NGTL Settlement approved in November 2013, a higher investment base on the NGTL System, and the impact of the NEB decision on the Canadian Mainline.

Canadian Pipelines

Canadian Mainline's comparable earnings increased by $29 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the NEB decision in March 2013 and higher incentive earnings. Among other items, the NEB approved an ROE of 11.50 per cent on 40 per cent deemed common equity for the years 2012 through to 2017 compared to the last approved ROE of 8.08 per cent on deemed common equity of 40 per cent that was used to record earnings in 2012 as well as an incentive mechanism based on total net revenues. The increase in comparable earnings relates almost fully to the higher ROE and some incentive earnings.

Net income for the NGTL System increased by $17 million for the three months ended December 31, 2013 compared to the same period in 2012 because of the impact of the 2013-2014 NGTL Settlement which included a higher ROE and incentive earnings and a higher average investment base associated with 2012 and 2013 capital expenditures. The settlement, approved by the NEB in November 2013, included an ROE of 10.10 per cent on 40 per cent deemed common equity compared to an ROE of 9.70 per cent on 40 per cent deemed common equity in 2012. The settlement also included annual fixed amounts for certain OM&A costs.

U.S. Pipelines

Comparable EBITDA for the U.S. and international pipelines decreased by US$30 million for the three months ended December 31, 2013 compared to the same period in 2012. This was the net effect of:

- lower transportation and storage revenues at ANR
- higher OM&A and costs relating to services provided by other pipelines at ANR
- lower contributions from GTN and Bison as a result of a reduction of our effective ownership in each pipeline from 83 per cent in 2012 to 50 per cent effective July 1, 2013
- higher contributions from Portland due to higher short term revenues.

Oil Pipelines

Comparable EBITDA for Oil Pipelines increased by $26 million primarily due to the Keystone Pipeline System which increased by $20 million for the three months ended December 31, 2013 compared to the same period in 2012. These increases reflected higher revenues primarily resulting from higher volumes.

Energy

Comparable EBITDA for Energy increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the effect of:

- higher equity income from Bruce Power mainly because of incremental earnings from Unit 4 due to fewer planned outage days and the return to service of Units 1 and 2
- higher earnings from U.S. Power mainly because of higher capacity prices in New York offset by lower volumes, primarily at the Ravenswood facility
- lower earnings from Western Power mainly because of lower realized power prices partly offset by the return to service of the Sundance A PPA Unit 1 in early September 2013 and Unit 2 in early October 2013.

Western Power's comparable EBITDA decreased by $24 million for the three months ended December 31, 2013 compared to the same period in 2012 due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A Unit 1 in early September 2013 and Unit 2 in early October 2013.

Average spot market power prices in Alberta decreased by 39 per cent to $48/MWh for the three months ended December 31, 2013 compared to the same period in 2012. This decrease was the result of changes in the Alberta power supply and demand balance reflecting the return of Sundance A Units 1 and 2, significantly fewer coal plant outages and higher wind output in fourth quarter 2013 compared to fourth quarter 2012.

Realized power prices on power sales can be higher or lower than spot market power prices in any given period, as a result of contracting activities.

Purchased volumes for the three months ended December 31, 2013 were higher compared to the same period in 2012 mainly because of the return to service of Sundance A Units 1 and 2.

Approximately 68 per cent of Western Power sales volumes were sold under contract this quarter compared to 80 per cent in fourth quarter 2012. To reduce exposure to spot market prices in Alberta, Western Power enters into fixed price forward sales to secure future revenue and a portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. The amount sold forward will vary depending on market conditions and market liquidity and has historically ranged between 25 to 75 per cent of expected future production with a higher proportion being hedged in the near term periods. Such forward sales may be completed with medium and large industrial and commercial companies and other market participants and will affect our average realized price (versus spot price) in future periods.

Equity income from Bruce A increased by $124 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was mainly due to:

- incremental earnings from Unit 4 due to the planned life extension outage which began in third quarter 2012 and was completed in April 2013
- incremental earnings from Units 1 and 2 which returned to service in October 2012
- higher realized prices.

U.S. Power's comparable EBITDA increased by US$17 million for the three months ended December 31, 2013 compared to the same period in 2012. The increase was the net effect of:

- higher realized capacity prices in New York
- higher realized power prices in New England offset by the impact of higher fuel costs
- lower generation, primarily at the Ravenswood facility.

Natural Gas Storage's comparable EBITDA increased by $7 million for the three months ended December 31, 2013 compared to the same period in 2012 mainly due to higher volumes at higher realized natural gas storage spreads and incremental earnings from CrossAlta resulting from the acquisition of the remaining 40 per cent interest in December 2012.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
Canadian Restructuring Proposal	Canadian Mainline business and services restructuring proposal and 2012 and 2013 Mainline final tolls application
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
fracking	Hydraulic fracturing. A method of extracting natural gas from shale rock
GHG	Greenhouse gas
HSE	Health, safety and environment
LNG	Liquefied natural gas
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
ASU	Accounting Standards Update
DRP	Dividend reinvestment plan
EBIT	Earnings before interest and taxes
EBITDA	Earnings before interest, taxes, depreciation and amortization
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
GAAP	U.S. generally accepted accounting principles

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOS	Department of State (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
ISO	Independent System Operator
LMCI	Land Matters Consultation Initiative (Canada)
NEB	National Energy Board (Canada)
OPA	Ontario Power Authority (Canada)
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission