Management's discussion and analysis

February 12, 2015

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, 2014.

This MD&A should be read with our accompanying December 31, 2014 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 120.

All information is as of February 12, 2015 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 and insurance claims
- 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 and insurance claims
- performance of our counterparties
- changes in market commodity prices
- 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 183 for other consolidated financial information on TransCanada for the last five 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).

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 U.S. GAAP and therefore may not be similar to 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 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 useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings.

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 useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period and is used to provide a consistent measure of the cash generating performance of our assets. See the Financial condition section 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	segmented earnings
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

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

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments
- gains or losses on sales of assets
- legal, contractual 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 unrealized changes in fair value do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

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 liquids pipelines, power generation and natural gas storage facilities.

THREE CORE BUSINESSES

We operate our business in three segments – Natural Gas Pipelines, Liquids 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 $59 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, 35 U.S. states and Mexico.

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
14 TC Offshore

Mexican Pipelines

15 Guadalajara
16 Tamazunchale

Under Construction

17 Mazatlan Pipeline
18 Topolobampo Pipeline

In Development

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

Liquids Pipelines

Canadian / U.S. Pipelines

25 Keystone Pipeline System
26 Cushing Marketlink

Under Construction

27 Houston Lateral
28 Houston Terminal
29 Keystone Hardisty Terminal
30 Grand Rapids Pipeline
31 Northern Courier Pipeline

In Development

32 Bakken Marketlink
33 Keystone XL
34 Heartland Pipeline
35 TC Terminals
36 Energy East Pipeline
37 Upland Pipeline

Energy

Canadian - Western Power

38 Bear Creek
39 Carseland
40 Coolidge[1]
41 Mackay River
42 Redwater
43 Sheerness PPA
44 Sundance A PPA
44 Sundance B PPA

Canadian - Eastern Power

45 Bécancour
46 Cartier Wind
47 Grandview
48 Halton Hills
49 Portlands Energy
50 Ontario Solar (8 Facilities)

Bruce Power

51 Bruce A
51 Bruce B

U.S. Power

52 Kibby Wind
53 Ocean State Power
54 Ravenswood
55 TC Hydro

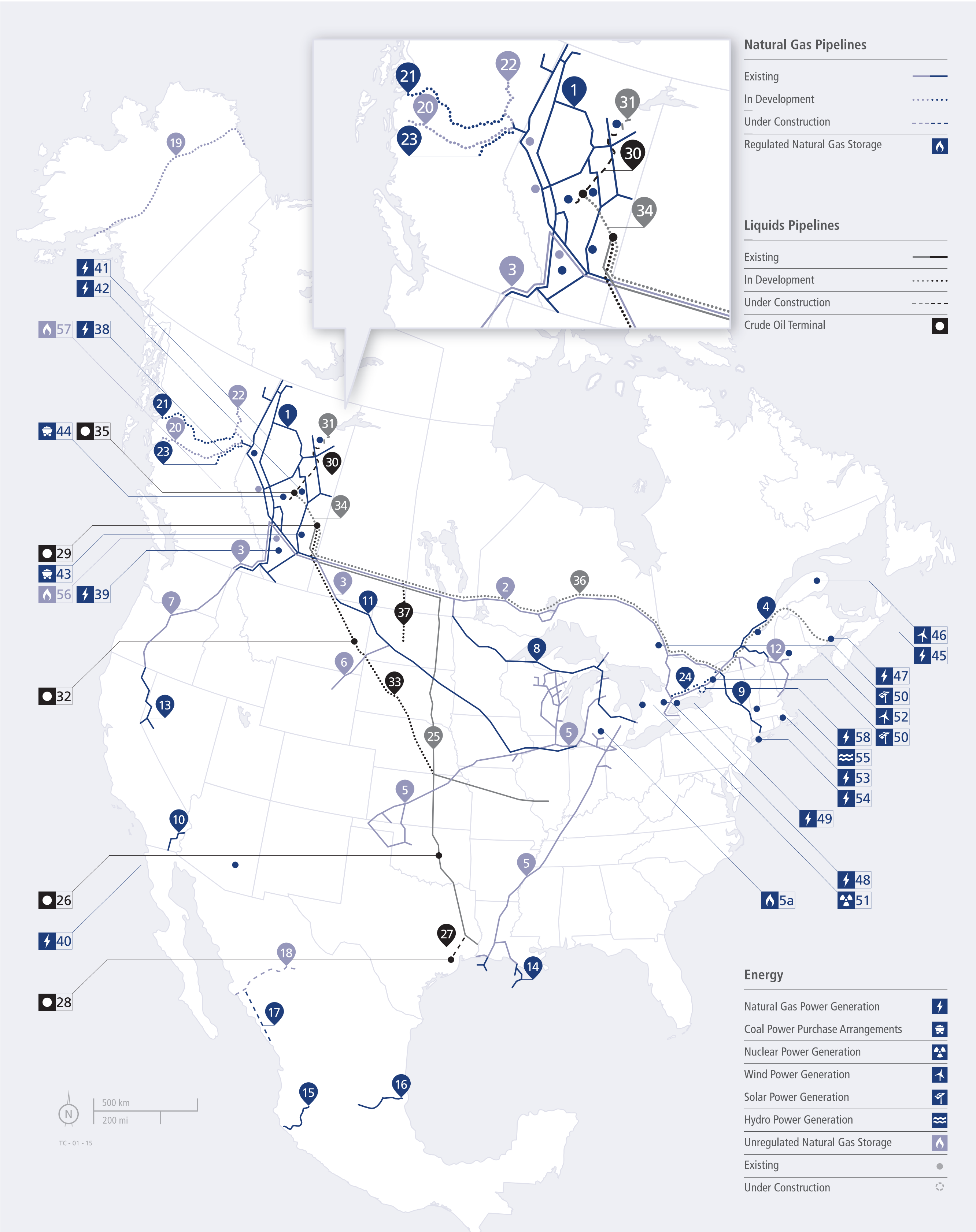
Unregulated Natural Gas Storage

56 CrossAlta
57 Edson

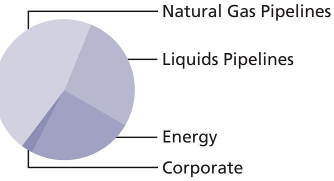
Under Construction

58 Napanee

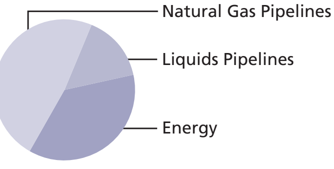
[1] Located in Arizona, results reported in Canadian - Western Power


Natural Gas Pipelines
Existing
In Development
Under Construction
Regulated Natural Gas Storage
Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
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
Under Construction
500 km
200 mi
N
TC - 01 - 15

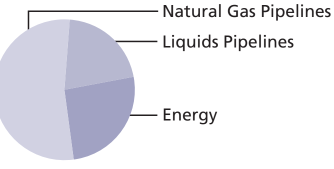
at December 31 (millions of $)	2014	2013
Total assets		
Natural Gas Pipelines	**27,103**	25,165
Liquids Pipelines	**16,116**	13,253
Energy	**14,197**	13,747
Corporate	**1,531**	1,733
	58,947	53,898



year ended December 31 (millions of $)	2014	2013
Total revenue		
Natural Gas Pipelines	**4,913**	4,497
Liquids Pipelines	**1,547**	1,124
Energy	**3,725**	3,176
	10,185	8,797

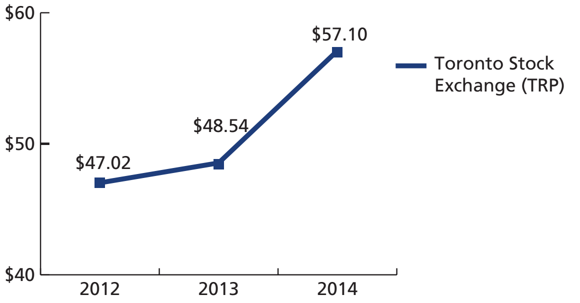


year ended December 31 (millions of $)	2014	2013
Segmented earnings		
Natural Gas Pipelines	**2,187**	1,881
Liquids Pipelines	**843**	603
Energy	**1,051**	1,113
Corporate	**(150)**	(124)
	3,931	3,473



Common share price

at December 31



Common shares outstanding – average

(millions)	
2014	708
2013	707
2012	705

as at February 9, 2015 Common shares	Issued and outstanding
	709 million

Preferred shares	Issued and outstanding	Convertible to
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	14 million	Series 4 preferred shares
Series 5	14 million	Series 6 preferred shares
Series 7	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares

Options to buy common shares	Outstanding	Exercisable
	8 million	5 million

OUR 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.

Our 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 $46 billion capital program, comprised of $12 billion in short-term projects and $34 billion in medium to long-term projects. These will contribute incremental earnings over the near, medium and long terms 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 to ensure we provide maximum shareholder value over the short, medium and long terms.

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 and 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 positioning: 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; stable and growing master limited partnership that complements our funding program; ability to balance an increasing dividend on our common shares while preserving financial flexibility to fund industry-leading capital program in all market conditions.
- 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.

CAPITAL PROGRAM

We are developing quality projects under our long-term capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flow.

Our capital program consists of $12 billion of small to medium-sized, shorter-term projects and $34 billion of commercially secured large-scale, medium and longer-term projects. Amounts presented exclude the impact of foreign exchange and capitalized interest.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

at December 31, 2014 (billions of $)	Segment	Expected In-Service Date	Estimated Project Cost	Amount Spent
Small to medium-sized, shorter-term				
Houston Lateral and Terminal	Liquids Pipelines	2015	US 0.6	US 0.4
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.7
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.2
Grand Rapids[1]	Liquids Pipelines	2016-2017	1.5	0.2
Heartland and TC Terminals	Liquids Pipelines	2017	0.9	0.1
Northern Courier	Liquids Pipelines	2017	0.9	0.2
Canadian Mainline – Other	Natural Gas Pipelines	2015-2016	0.5	-
NGTL System – North Montney	Natural Gas Pipelines	2016-2017	1.7	0.1
– 2016/17 Facilities	Natural Gas Pipelines	2016-2017	2.7	-
– Other	Natural Gas Pipelines	2015-2016	0.4	0.1
Napanee	Energy	2017 or 2018	1.0	0.1
			11.6	2.1
Large-scale, medium and longer-term				
Upland	Liquids Pipelines	2018	0.6	-
Keystone projects				
Keystone XL[2]	Liquids Pipelines	[3]	US 8.0	US 2.4
Keystone Hardisty Terminal	Liquids Pipelines	[3]	0.3	0.1
Energy East projects				
Energy East[4]	Liquids Pipelines	2018	12.0	0.5
Eastern Mainline	Natural Gas Pipelines	2017	1.5	-
BC west coast LNG-related projects				
Coastal GasLink	Natural Gas Pipelines	2019+	4.8	0.2
Prince Rupert Gas Transmission	Natural Gas Pipelines	2019+	5.0	0.3
NGTL System – Merrick	Natural Gas Pipelines	2020	1.9	-
			34.1	3.5
			45.7	5.6

1 Represents our 50 per cent share.
2 Estimated project cost dependent on the timing of the Presidential permit.
3 Approximately two years from the date the Keystone XL permit is received.
4 Excludes transfer of Canadian Mainline natural gas assets.

2014 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 similar to 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 24 for more information about the non-GAAP measures we use and page 112 for a reconciliation to their GAAP equivalents.

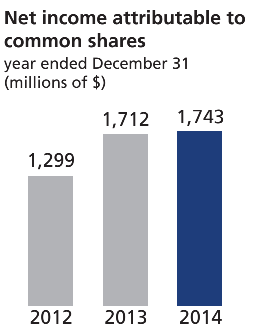
year ended December 31 (millions of $, except per share amounts)	**2014**	**2013**	**2012**
Revenue	**10,185**	8,797	8,007
Net income attributable to common shares	**1,743**	1,712	1,299
per common share – basic & diluted	**$2.46**	$2.42	$1.84
Comparable EBITDA	**5,521**	4,859	4,245
Comparable earnings	**1,715**	1,584	1,330
per common share	**$2.42**	$2.24	$1.89
Operating cash flow			
Funds generated from operations	**4,268**	4,000	3,284
(Increase)/decrease in working capital	**(189)**	(326)	287
Net cash provided by operations	**4,079**	3,674	3,571
Investing activities			
Capital spending – capital expenditures	**3,550**	4,264	2,595
Capital spending – projects under development	**807**	488	3
Equity investments	**256**	163	652
Acquisitions, net of cash acquired	**241**	216	214
Proceeds from sale of assets, net of transaction costs	**196**	-	-
Balance sheet			
Total assets	**58,947**	53,898	48,396
Long-term debt	**24,757**	22,865	18,913
Junior subordinated notes	**1,160**	1,063	994
Preferred shares	**2,255**	1,813	1,224
Non-controlling interests	**1,583**	1,611	1,425
Common shareholders' equity	**16,815**	16,712	15,687
Dividends declared			
per common share	**$1.92**	$1.84	$1.76
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	**$1.00**	$0.91	-
per Series 9 preferred share[1]	**$1.09**	-	-

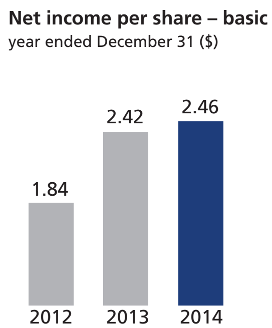
1 Issued January 20, 2014.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
Segmented earnings			
Natural Gas Pipelines	**2,187**	1,881	1,808
Liquids Pipelines	**843**	603	553
Energy	**1,051**	1,113	579
Corporate	**(150)**	(124)	(111)
Total segmented earnings	**3,931**	3,473	2,829
Interest expense	**(1,198)**	(985)	(976)
Interest income and other	**91**	34	85
Income before income taxes	**2,824**	2,522	1,938
Income tax expense	**(831)**	(611)	(466)
Net income	**1,993**	1,911	1,472
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Net income attributable to controlling interests	**1,840**	1,786	1,354
Preferred share dividends	**(97)**	(74)	(55)
Net income attributable to common shares	**1,743**	1,712	1,299
Net income per common share – basic and diluted	**$2.46**	$2.42	$1.84

Net income attributable to common shares





Net income attributable to common shares in 2014 was $1,743 million (2013 – $1,712 million; 2012 – $1,299 million). The following specific items were recognized in net income in 2012 to 2014:

2014

- a gain of $99 million after tax on the sale of Cancarb Limited and its related power generation business
- a net loss of $32 million after tax resulting from a termination payment to Niska Gas Storage for contract restructuring
- a gain of $8 million after tax on the sale of our 30 per cent interest in Gas Pacifico/INNERGY

2013

- net income of $84 million recorded in 2013 related to 2012 from the National Energy Board's (NEB) 2013 decision on the Canadian Restructuring Proposal (NEB 2013 Decision)
- a favourable tax adjustment of $25 million due to the enactment of Canadian Federal tax legislation relating to Part VI.I tax

2012

- an after-tax charge of $15 million 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 items discussed above were excluded from comparable earnings for the relevant periods. Certain unrealized fair value adjustments relating to risk management activities are also excluded from comparable earnings. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

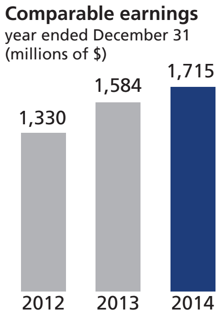
Reconciliation of net income to comparable earnings

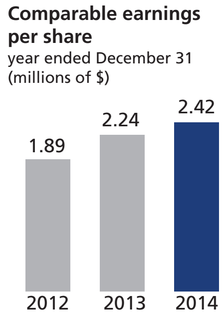
year ended December 31 (millions of $, except per share amounts)	**2014**	**2013**	**2012**
Net income attributable to common shares	**1,743**	1,712	1,299
Specific items (net of tax):			
Cancarb gain on sale	**(99)**	-	-
Niska contract termination	**32**	-	-
Gas Pacifico/INNERGY gain on sale	**(8)**	-	-
NEB 2013 Decision – 2012	**-**	(84)	-
Part VI.I income tax adjustment	**-**	(25)	-
Sundance A PPA arbitration decision – 2011	**-**	-	15
Risk management activities[1]	**47**	(19)	16
Comparable earnings	**1,715**	1,584	1,330
Net income per common share	**$2.46**	$2.42	$1.84
Specific items (net of tax):			
Cancarb gain on sale	**(0.14)**	-	-
Niska contract termination	**0.04**	-	-
Gas Pacifico/INNERGY gain on sale	**(0.01)**	-	-
NEB 2013 Decision – 2012	**-**	(0.12)	-
Part VI.I income tax adjustment	**-**	(0.04)	-
Sundance A PPA arbitration decision – 2011	**-**	-	0.02
Risk management activities[1]	**0.07**	(0.02)	0.03
Comparable earnings per share	**$2.42**	$2.24	$1.89

1

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Foreign exchange	**(21)**	(9)	(1)
Income tax attributable to risk management activities	**27**	(16)	6
Total (losses)/gains from risk management activities	**(47)**	19	(16)

Comparable earnings





Comparable earnings in 2014 were $131 million higher than in 2013, an increase of $0.18 per share.

The increase in comparable earnings was primarily the net result of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System which was placed in service in January 2014
- higher interest expense from debt issuances and lower capitalized interest due to projects placed in service
- lower earnings from Western Power as a result of lower realized power prices
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from U.S. Natural Gas Pipelines due to higher transportation revenues at Great Lakes reflecting colder winter weather and increased demand, partially offset by lower contributions from GTN and Bison following the reductions in our effective ownership in July 2013 (GTN and Bison) and October 2014 (Bison)
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices for the New York and New England facilities
- higher earnings from the Canadian Mainline due to higher incentive earnings
- incremental earnings from Eastern Power primarily due to solar facilities acquired in 2013 and 2014.

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

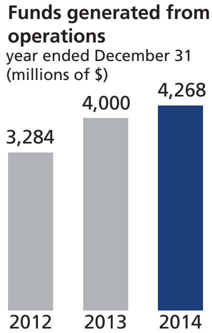
The increase in comparable earnings was the net result of:

- 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 NEB 2013 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 PPAs
- lower contributions from U.S. Natural Gas Pipelines because of lower earnings at ANR and Great Lakes.

Cash flows

Funds generated from operations

Funds generated from operations were 7 per cent higher this year compared to 2013 primarily for the same reasons comparable earnings were higher, as described above.

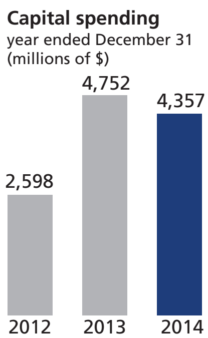


Funds used in investing activities

Capital spending [1]

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Natural Gas Pipelines	**2,136**	2,021	1,389
Liquids Pipelines	**1,969**	2,529	1,148
Energy	**206**	152	24
Corporate	**46**	50	37
	4,357	4,752	2,598

1 Capital spending includes capital expenditures and capital projects under development.



We invested $4.4 billion in capital projects in 2014 as part of our ongoing capital program which was consistent with our revised outlook in our third quarter 2014 report to shareholders. 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 flows and to maximize returns to shareholders for years to come.

Equity investments and acquisitions

In 2014, we invested $256 million in our equity investments primarily related to the construction of Grand Rapids. We also spent $241 million on the acquisition of four additional solar facilities from Canadian Solar Solutions Inc.

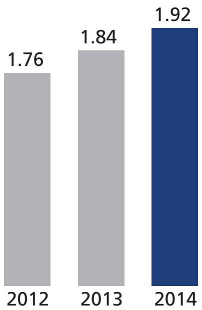
Balance sheet

We continue to maintain a strong balance sheet while growing our total assets by $10.6 billion since 2012. At December 31, 2014, common equity represented 38 per cent (40 per cent in 2013) of our capital structure. See page 91 for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by eight per cent to $0.52 per share for the quarter ending March 31, 2015 which equates to an annual dividend of $2.08 per share. This is the 15th consecutive year we have increased the dividend on our common shares.

Dividends declared per share
year ended December 31 ($)



Dividend reinvestment plan

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

Quarterly dividend on our common shares

$0.52 per share (for the quarter ending March 31, 2015)

Annual dividends on our preferred shares

Series 1 $0.82[1]

Series 2 $0.69[2]

Series 3 $1.00

Series 5 $1.10

Series 7 $1.00

Series 9 $1.06

1 In December 2014, 12.5 million Series 1 preferred shares were converted to Series 2 preferred shares. See the Financial condition section for more information.

2 Annualized amount of the first quarterly floating rate period as the floating rate will reset each quarter. See the Financial condition section for more information.

Cash dividends

year ended December 31 (millions of $)	2014	2013	2012
Common shares	**1,345**	1,285	1,226
Preferred shares	**94**	71	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 2015 to be higher than 2014, mainly due to the net effect of the following:

- increase in the average investment base for the NGTL System
- incremental earnings from solar facilities acquired in 2014 and higher contractual earnings at Bécancour
- anticipated higher net margins and production from the U.S. Power assets
- expected earnings associated with increased contracts for ANR
- decline in earnings for the Canadian Mainline as a result of the 2015 – 2030 Tolls and Tariff Application
- reduced equity income from Bruce Power due to increased planned maintenance activity and higher operating costs
- lower Alberta power prices and lower contributions from our Natural Gas Storage operations.

Earnings will also be impacted by additional Corporate segment items including increased AFUDC reflecting continued growth and capital spending primarily on Topolobampo, Mazatlan, the NGTL System and Energy East.

Results from our U.S. businesses are subject to fluctuations in foreign exchange rates. These fluctuations are largely offset by interest on our U.S. dollar denominated debt as well as our hedging activities which are included in our Corporate segment.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segment are affected by regulatory decisions and the timing of these decisions. Earnings are also impacted by market conditions, which drive the level of demand and the rate, we secure for our services.

Canadian Mainline earnings are anticipated to be lower in 2015 primarily as the result of the 2015 – 2030 Tolls and Tariff Application approved by the NEB in November 2014. These lower earnings are expected to be largely offset by growth in the NGTL System investment base 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.

U.S. and International Gas Pipelines earnings are expected to be higher in 2015 primarily due to new long-term contracts for ANR originating from the Utica/Marcellus shale plays.

Earnings from our existing Mexican pipeline operations are expected to be consistent with 2014.

Liquids Pipelines

Earnings in 2015 from the Liquids Pipelines segment are not expected to be significantly different than 2014. We continue to seek further operational efficiencies which would, depending on market demand, improve capacity and flows on the Keystone Pipeline System.

Over time, Liquids Pipelines' earnings will increase as projects currently in development are placed in service.

Energy

Earnings in the Energy segment are generally maximized by maintaining and optimizing the operations of our power plants and through various marketing activities. Although a significant portion of Energy's output is sold under long-term contracts, output that is sold under shorter-term arrangements or at spot prices will continue to be affected by fluctuations in commodity prices.

Western Power earnings are anticipated to be lower in 2015 as a result of changing market conditions. Despite continued robust power demand in Alberta, exclusive of any market supply challenges, new supply additions in 2015 are expected to result in downward pressure on spot prices.

Eastern Power earnings in 2015 are expected to be higher as a result of a full year of operations from the additional solar assets acquired in 2014 as well as higher contractual earnings at Bécancour.

Bruce Power equity income is expected to be lower primarily due to the increased planned maintenance activity and higher operating costs.

U.S. Power earnings are anticipated to increase as a result of higher net energy margins and production partially offset by lower capacity prices for Ravenswood as a result of new supply entering the market in 2015.

Natural Gas Storage earnings are expected to be slightly lower in 2015 with fewer opportunities to realize shorter-term gas cycling gains such as those realized during periods of extreme volatility in 2014.

Consolidated capital spending and equity investments

We expect to spend approximately $6 billion in 2015 on new and existing capital projects. The 2015 capital spending relates to Natural Gas Pipeline projects including NGTL System expansion, the Canadian Mainline, Topolobampo, and Mazatlan; Liquids Pipeline projects including Grand Rapids, Northern Courier, Energy East and Heartland; and Energy projects including Napanee.

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 – 11,000 km (6,600 miles).

We also 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.

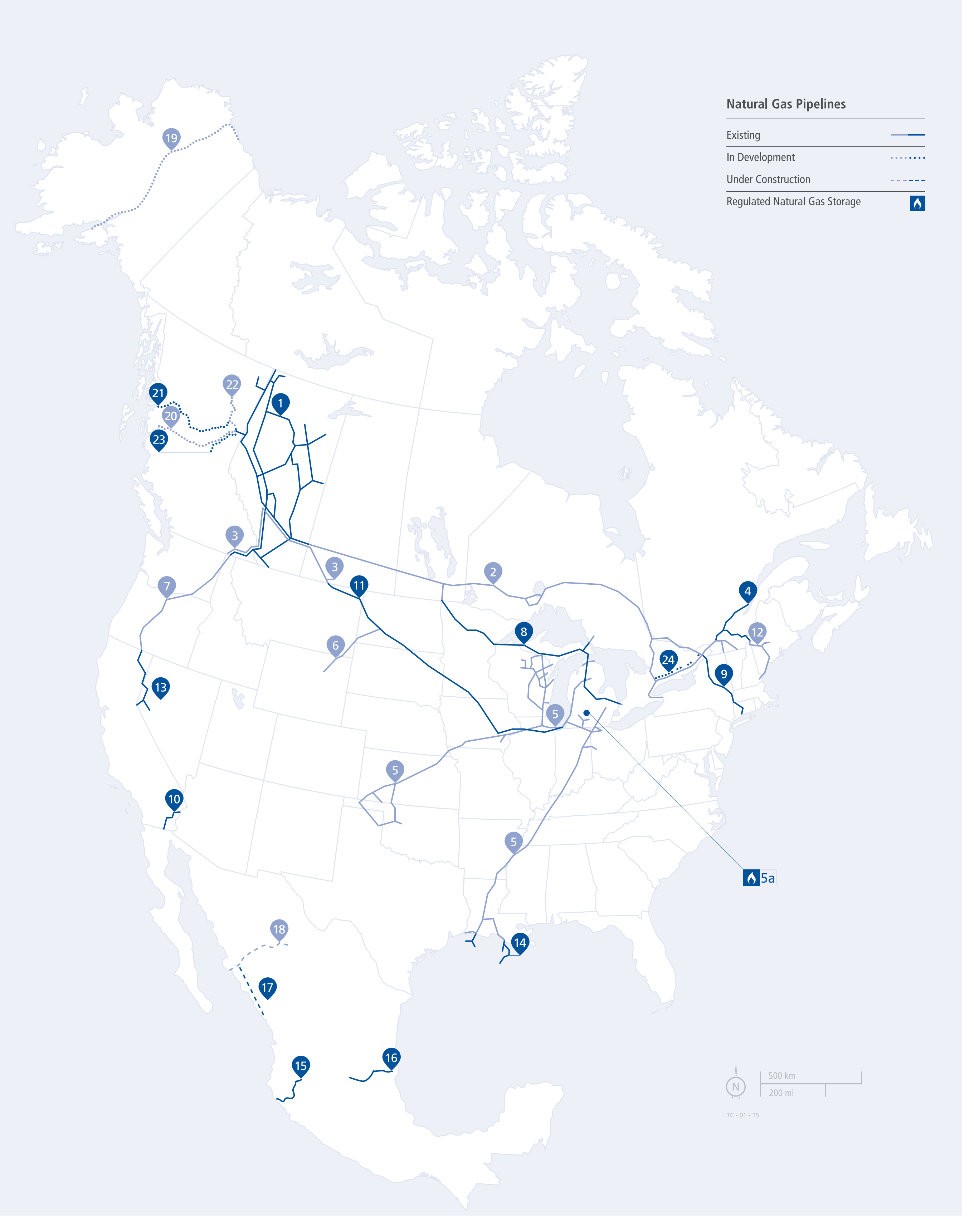
Strategy at a glance

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 the Gulf of Mexico
- additional new 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 transportation requirements for supply and 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	24,525 km (15,239 miles)	Receives, transports and delivers natural gas within Alberta and 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 and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and connects with the Portland pipeline system that serves the northeast U.S.	50%
	U.S. pipelines			
5	ANR Pipeline	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
5a	ANR 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 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
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 49.8 per cent of the system through the combination of our 30 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	49.8%
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 66.7 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 28.3 per cent interest in TC PipeLines, LP	66.77%
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%
10	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/Mexico border. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
11	Northern Border	2,265 km (1,407 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 14.2 per cent of the system through our 28.3 per cent interest in TC PipeLines, LP	14.2%

	length	description	effective ownership
U.S. pipelines			
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 markets in northeastern California and northwestern Nevada. We effectively own 28.3 per cent of the system through our interest in TC PipeLines, LP	28.3%
14 TC Offshore	958 km (595 miles)	Gathers and transports natural gas within the Gulf of Mexico with subsea pipeline and seven offshore platforms to connect in Louisiana with our ANR pipeline system.	100%
Mexican pipelines			
15 Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco	100%
16 Tamazunchale	365 km (227 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to to El Sauz, Queretaro	100%
Under construction			
17 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%
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	25%
20 Coastal GasLink	670 km* (416 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	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
22 North Montney Mainline	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project	100%
23 Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
24 Eastern Mainline	245 km* (152 miles)	Various pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project	100%
NGTL 2016/17 Facilities**	540 km* (336 miles)	The expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests on the NGTL System	100%

* Pipe lengths are estimates as final route is still under design
** Facilities are not shown on the map

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable EBITDA	**3,241**	2,852	2,741
Comparable depreciation and amortization	**(1,063)**	(1,013)	(933)
Comparable EBIT	**2,178**	1,839	1,808
Specific items:			
Gas Pacifico/INNERGY gain on sale	**9**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Segmented earnings	**2,187**	1,881	1,808

Natural Gas Pipelines segmented earnings in 2014 increased by $306 million compared to 2013 and included $9 million related to the gain on sale of Gas Pacifico/INNERGY in November 2014 whereas the year ended December 31, 2013 included $42 million related to the 2012 impact of the NEB 2013 Decision. These amounts have been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Canadian Pipelines			
Canadian Mainline	**1,334**	1,121	994
NGTL System	**856**	846	749
Foothills	**106**	114	120
Other Canadian pipelines[1]	**22**	26	29
Canadian Pipelines – comparable EBITDA	**2,318**	2,107	1,892
Comparable depreciation and amortization	**(821)**	(790)	(715)
Canadian Pipelines – comparable EBIT	**1,497**	1,317	1,177
U.S. and International Pipelines (in US$)			
ANR	**189**	188	254
TC PipeLines, LP[1,2]	**88**	72	74
Great Lakes[3]	**49**	34	62
Other U.S. pipelines (Bison[4], GTN[5], Iroquois[1], Portland[6])	**132**	183	223
Mexico (Guadalajara, Tamazunchale)	**160**	100	99
International and other[1,7]	**(10)**	(4)	5
Non-controlling interests[8]	**241**	186	161
U.S. and International Pipelines – comparable EBITDA	**849**	759	878
Comparable depreciation and amortization	**(219)**	(217)	(218)
U.S. and International Pipelines – comparable EBIT	**630**	542	660
Foreign exchange impact	**68**	15	-
U.S. and International Pipelines – comparable EBIT (Cdn$)	**698**	557	660
Business Development comparable EBITDA and comparable EBIT	**(17)**	(35)	(29)
Natural Gas Pipelines – comparable EBIT	**2,178**	1,839	1,808
Summary			
Natural Gas Pipelines – comparable EBITDA	**3,241**	2,852	2,741
Comparable depreciation and amortization	**(1,063)**	(1,013)	(933)
Natural Gas Pipelines – comparable EBIT	**2,178**	1,839	1,808

1 Results from TQM, Northern Border, Iroquois, TransGas and Gas Pacifico/INNERGY reflect our share of equity income from these investments. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

2 In August 2014, TC PipeLines, LP began its at-the-market equity issuance program which will decrease our ownership interest in TC PipeLines, LP going forward. 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. On October 1, 2014, we sold our remaining 30 per cent interest in Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership of Bison, GTN, and Great Lakes through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of			
	October 1, 2014	July 1, 2013	May 22, 2013	January 1, 2012
TC PipeLines, LP	28.3	28.9	28.9	33.3
Effective ownership through TC PipeLines, LP:				
Bison	28.3	20.2	7.2	8.3
GTN	19.8	20.2	7.2	8.3
Great Lakes	13.1	13.4	13.4	15.5

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

4 Effective October 1, 2014 we have no direct ownership in Bison. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013, 75 per cent effective May 2011 and 100 per cent prior to that date.

5 Effective July 1, 2013, reflects our direct ownership interest of 30 per cent. Prior to that our direct ownership interest was 75 per cent.

6 Represents our 61.7 per cent ownership interest.

7 Includes our share of the equity income from Gas Pacifico/INNERGY and TransGas as well as general and administration costs relating to our U.S. and International Pipelines. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

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

Canadian Pipelines

year ended December 31 (millions of $)	2014	2013	2012
Net income			
Canadian Mainline – net income	**300**	361	187
Canadian Mainline – comparable earnings	**300**	277	187
NGTL System	**241**	243	208
Average investment base			
Canadian Mainline	**5,690**	5,841	5,737
NGTL System	**6,236**	5,938	5,501

Net income and comparable EBITDA for our rate-regulated Canadian Pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity, carrying charges owed to shippers on the Canadian Mainline Tolls Stabilization Account (TSA), and incentive earnings. Changes in depreciation, financial charges and income 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 $23 million compared to 2013 because of higher incentive earnings, partially offset by higher carrying charges owed to shippers on the positive TSA balance and a lower average investment base. Among other things, the NEB 2013 Decision set out an ROE of 11.50 per cent on deemed common equity of 40 per cent for the years 2012 through 2017. Net income of $361 million recorded in 2013 included $84 million related to the 2012 impact of the NEB 2013 Decision, which was excluded from comparable earnings. Comparable earnings in 2013 were $90 million higher than 2012 because of the impact of the NEB 2013 Decision which approved incentive earnings and a higher ROE. The ROE used to record earnings in 2012 was 8.08 per cent on 40 per cent deemed common equity.

Net income for the NGTL System was $2 million lower in 2014 compared to 2013. The decrease in net income was due to increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013, partially offset by a higher average investment base. The settlement included an ROE of 10.10 per cent on deemed common equity of 40 per cent and included annual fixed amounts for certain OM&A costs. Net income in 2013 was $35 million higher than 2012 because of a higher average investment base and a higher ROE. In 2012, the NGTL System was operating under the 2010-2012 Settlement which had an ROE of 9.70 per cent on deemed common equity of 40 per cent and included an annual fixed amount for certain OM&A costs.

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 as well as 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$90 million higher in 2014 than 2013. This was due to the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenue at Great Lakes mainly due to colder winter weather and increased demand
- lower contributions from GTN and Bison following the reductions in our effective ownership in each pipeline in July 2013 (GTN and Bison) and October 2014 (Bison)
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

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 partially 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
- a stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Comparable depreciation and amortization

Comparable depreciation and amortization was $50 million higher in 2014 than in 2013 mainly because of a higher rate base for the NGTL System. Depreciation and amortization was $80 million higher in 2013 than in 2012 mainly because of a higher rate base for the NGTL System, as well as the impact of the Mainline NEB 2013 Decision discussed above.

Business development

In 2014, business development expenses were $18 million lower than 2013 due to a change in scope on the Alaska project and lower administrative costs, partially offset by higher spending on Mexican projects. Business development expenses were $6 million higher in 2013 compared to 2012 mainly due to a change in scope on the Alaska project. See page 54 for further discussion on Alaska.

OUTLOOK

Canadian Pipelines

Earnings

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

For 2015, the Canadian Mainline will operate under the terms of the 2015 – 2030 Tolls and Tariff Application, the fundamentals of which were approved by the NEB in November 2014. The terms of the application decision include a lower ROE of 10.10 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax contribution through tolls from us. As a result, we expect Canadian Mainline 2015 earnings to be lower than 2014.

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 rising demand in the oil sands market in northeastern Alberta. We expect the growing investment base to have a positive impact on NGTL System earnings in 2015.

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 in recent years, which resulted in reduced earnings in 2013 and 2014 as transportation and storage values were depressed to historically low levels.

ANR has secured new long term contracts and extended terms at maximum recourse rates for significant volumes originating from the Utica/Marcellus shale plays with contract start dates from late 2014 through late 2015. We continue to seek opportunities to expand upon this success along with those opportunities associated with continued growth in end use markets for natural gas. In addition, ANR and Great Lakes are examining commercial, regulatory and operational changes to continue to optimize their position in response to positive developments in supply fundamentals. As a result, we expect 2015 earnings from our U.S. Pipelines to increase slightly from 2014.

Mexican Pipelines

The 2015 earnings for our current operating assets in Mexico are expected to be consistent with 2014 due to the nature of the long-term contracts applicable to our Mexican pipeline systems.

Capital spending

We spent a total of $2.1 billion in 2014 for our natural gas pipelines in Canada, the U.S. and Mexico, and expect to spend $3.4 billion in 2015 primarily on the NGTL System expansion projects, the Topolobampo and

Mazatlan pipelines in Mexico and Canadian Mainline capacity projects. See page 105 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 network at 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 FERC and in Mexico by the 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. Costs of operating the systems include a return on our capital invested in the assets or rate base, as well as the recovery of the rate base over time through depreciation. Other costs recovered include OM&A costs, income and property taxes, and interest on debt. 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 our investors. As the pipeline operator within these jurisdictions, we 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, including performance incentives, 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. The Canadian Mainline, however, operates under a fixed toll arrangement for its longer-term firm transportation services and has the flexibility to price its shorter-term and interruptible services in order to maximize its revenue.

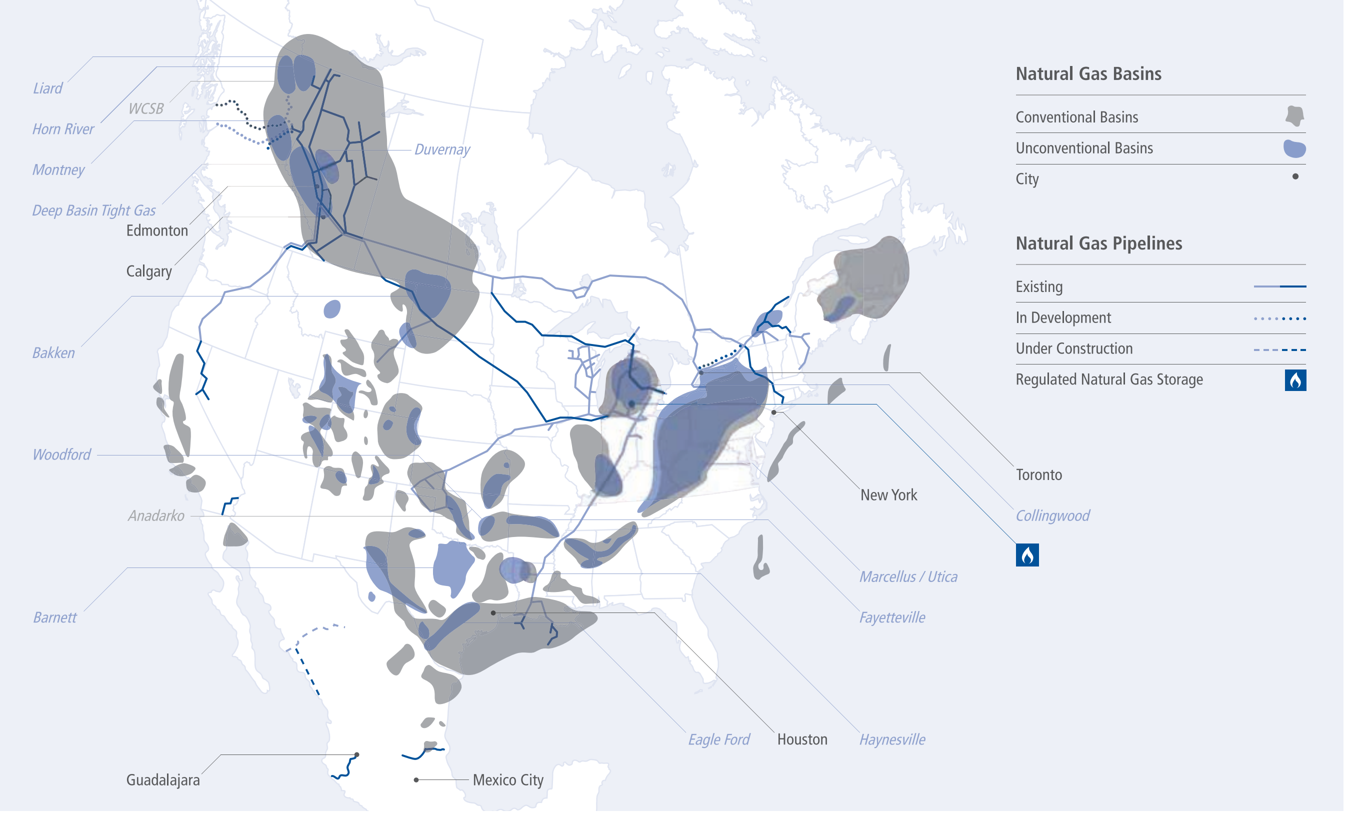
The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they allow for the collection or refund of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation puts our U.S. pipelines at risk for the difference in expected 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 the return on the capital invested to be too high.

Our Mexican pipelines have approved tariffs, services and related rates. However, most of 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 changes in the location of markets and level of 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 supply. The WCSB is currently estimated to have 150 trillion cubic feet of remaining conventional resources and a technically accessible unconventional resource base of over 700 trillion cubic feet. The total recoverable WCSB resource base has recently more than quadrupled with the advent of technology that can economically access unconventional gas areas in the basin. Production from the WCSB increased slightly in 2014 after decreasing every year since 2007 and is expected to continue to increase over the next several years. The Montney and Horn River shale play formations and the Liard basin in northeastern B.C. are also part of the WCSB and have recently become a significant source of natural gas. We expect production from the Montney play that is currently just under 3 Bcf/d, to grow to approximately 6 Bcf/d by 2020, depending on the economics of exploration and production compared to other, mainly U.S., sources and the progress of proposed B.C. west coast LNG exports.

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. The largest shale developments for natural gas are the Utica/Marcellus basins in the northeast U.S. These basins have grown from essentially no production prior to 2008 up to 16 Bcf/d at the end of 2014. They are forecast to grow to 25 Bcf/d by 2020. Other natural gas supply from shale in the U.S. includes the Haynesville, Barnett, Eagle Ford and Fayetteville plays.

The overall supply of natural gas in North America is forecast to increase significantly over the next decade (by almost 20 Bcf/d or 22 per cent by 2020), and is expected to continue to increase over the long term for several reasons:

- continued technological progress with horizontal drilling and multi-stage hydraulic fracturing or fracking. This is increasing the technically accessible resource base of existing basins and emerging regions, such as the Marcellus and Utica in the U.S. northeast, and the Montney and Horn River areas in northeastern B.C.
- these technologies are also being applied to existing oil fields where further recovery of the resource is now possible. There is often associated gas discovered in the exploration and production of liquids-rich hydrocarbon basins, (for example, the Bakken oil fields) which also contributes to an increase in 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 expected to change historical gas pipeline flow patterns, generally from long-haul, long-term firm contracted capacity to shorter-distance, shorter-term contracts. Along with our competitors, we are restructuring our tolls and service offerings to capture this growing northeast supply and North American demand.

The Canadian Mainline is well positioned to offer optionality of supply to eastern Canadian and northeast U.S. markets, while still ensuring the opportunity to recover our costs including a return on the investment for both existing and new infrastructure as required.

Growing northeast supply has had a positive impact for both the Mainline, with new proposed facilities in eastern Canada, and our ANR U.S. pipeline assets, with significant new long-term contracts for service. The increase in supply in northeastern B.C. has created opportunities for us to plan and build, subject to regulatory approval and a positive final investment decisions (FID), new large pipeline infrastructure on the NGTL System to move the natural gas to markets, including proposed LNG exports and growing Alberta market demand.

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 continue to progress opportunities to sell natural gas to global markets, which involves connecting natural gas supplies to new LNG export terminals which are proposed primarily along the west coast of B.C. and the U.S. Gulf of Mexico. Assuming the receipt of all necessary regulatory and other approvals, the proposed facilities along the west coast of B.C. are expected to become operational later in this decade. The U.S Gulf Coast also has several LNG export facilities in various stages of development or construction. LNG exports are expected to ramp up from this area, with initial deliveries beginning as early as late 2015. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

Commodity Prices

In general, the profitability of our gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and its price impact can have an indirect impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure.

More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. Development of technology for shale gas supply basins that are closer to markets historically served by long-haul pipelines has resulted in changes to flow patterns of existing natural gas pipeline infrastructure that includes reversing direction of flow and different distances of haul, 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 of our strategy in 2014. The cold 2013/14 winter coupled with the ability to price our discretionary services at market prices, resulted in a significant increase in long-haul firm transportation originating at Empress as well as increased revenue collection from the utilization of Mainline transportation services. The regulatory framework in place at the time did not allow us the opportunity to meet growing demand for new gas supplies to eastern Canada and recover the costs for those investments. As a result, an application for approval of 2015 to 2030 tolls was filed with the NEB based on the components reached in a settlement with the three major LDCs in Ontario and Québec. In November 2014, the NEB approved the application as filed (2015 – 2030 Tolls and Tariff Application). This approval sets the stage to advance capital projects in eastern Canada to meet the needs of our eastern Canada and northeast U.S. shippers seeking alternative supply sources. It also ensures a reasonable opportunity to recover the costs associated with our existing assets as well as those related to new pipeline investments.

In 2015, we will continue to advance the planned conversion of portions of the Canadian Mainline from natural gas service to crude oil service. The Energy East Pipeline is a planned project, subject to regulatory approval, to convert approximately 3,000 km (1,864 miles) of the Canadian Mainline from the Alberta border to a point in eastern Ontario, southeast of Ottawa, to crude oil service. We are committed to ensuring that our gas shipper community continues to receive transportation service to meet their firm service requirements.

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 other existing competing pipelines. Connections to new supply and new or growing demand continues to support 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 16 Bcf/d by 2020. The NGTL System is well positioned to connect WCSB supply to meet expected demand for proposed LNG exports on the B.C. coastline. Obtaining the necessary regulatory approvals to extend and expand the NGTL System in northeastern B.C. to connect the Montney shale area was a key focus in 2014. A hearing process that examined the merits of our North Montney Pipeline project concluded in December 2014 and the NEB decision is expected by the end of April 2015.

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

- Utica/Marcellus supply growth and increased demand for natural gas to supply Gulf Coast LNG export development supports additional ANR utilization, including the Lebanon Lateral project. We have attracted Utica supply to the ANR System with additional phases of further expansion expected
- expected continued growth in gas-fired generation should lead to increased load on our pipelines, including the 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 customer in Iowa.

Management expects to drop down our remaining U.S. natural gas pipeline assets into TC PipeLines, LP as a means of funding a portion of our capital growth program, subject to the approvals of TC PipeLines, LP's board and our board as well as market conditions.

Our focus in Mexico in 2015 is to advance the construction phase for the Mazatlan and Topolobampo pipelines and to continue operating our existing facilities safely and reliably. 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 our strategic priorities.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

NGTL System

We continue to experience significant growth on the NGTL System as a result of growing natural gas supply in northwestern Alberta and northeastern B.C. from unconventional gas plays and substantive growth in intra-basin delivery markets. This demand growth is driven primarily by oil sands development, gas-fired electric power generation and expectations of B.C. west coast LNG projects. This demand for NGTL System services is expected to result in approximately 4.0 Bcf/d of incremental firm services with approximately 3.1 Bcf/d related to firm receipt services and 0.9 Bcf/d related to firm delivery services. We will be seeking regulatory approvals in 2015 to construct new facilities to meet service requests of approximately 540 km (336 miles) of pipeline, seven compressor stations, and 40 meter stations that will be required in 2016 and 2017 (2016/17 Facilities). The estimated total capital cost for the facilities is approximately $2.7 billion.

Including the new 2016/17 Facilities, the North Montney Mainline, the Merrick Mainline, and other new supply and demand facilities, the NGTL System has approximately $6.7 billion of commercially secured projects in various stages of development.

North Montney Mainline

The $1.7 billion North Montney Pipeline is a proposed extension and expansion of the NGTL System to receive and transport natural gas from the North Montney area of B.C. The hearing for the application before the NEB to build and operate this project concluded in December 2014. We expect the NEB to issue its report and recommendations for the project by the end of April 2015.

Merrick Mainline

In June 2014, we announced the signing of agreements for approximately 1.9 Bcf/d of firm natural gas transportation services to underpin the development of a major extension of our NGTL System.

The proposed Merrick Mainline will transport natural gas sourced through the NGTL System to the inlet of the proposed Pacific Trail Pipeline that will terminate at the Kitimat LNG Terminal at Bish Cove near Kitimat, B.C. The proposed project will be an extension from the existing Groundbirch Mainline section of the NGTL System beginning near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C. The $1.9 billion project will consist of approximately 260 km (161 miles) of 48-inch diameter pipe.

Subject to the necessary approvals, which includes the regulatory approval from the NEB for us to build and operate the pipeline, and a positive final investment decision for the Kitimat LNG project, we expect the Merrick Mainline to be in service in first quarter 2020.

2015 Revenue Requirement Settlement

We received NEB approval on February 2, 2015 for our revenue requirement settlement with our shippers for 2015 on the NGTL System. The terms of the one year settlement include continuation of the 2014 ROE of 10.10 per cent on 40 per cent deemed equity, continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed operating, maintenance and administrative expense amount that is based on an escalation of 2014 actual costs.

Canadian Mainline

2015 – 2030 Tolls and Tariff Application

On November 28, 2014, the NEB approved the Canadian Mainline's 2015 – 2030 Tolls and Tariff Application. The application reflected components of a settlement between the Canadian Mainline and the three major LDCs in Ontario and Québec. The approval of this application provides a long term commercial platform for both the Canadian Mainline and its shippers with a known toll design for 2015 to 2020 and certain parameters for a toll-setting methodology up to 2030. The platform 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.

Highlights of the approved application include:

- our commitment to add increased pipeline capacity that allows eastern Canadian markets more access to Dawn and Niagara area supplies
- renewal provisions that will give us the tools to gain more certainty over capacity requirements
- fixed price tolls on one-year and longer firm transportation service
- continued pricing discretion for shorter term and interruptible service
- a known revenue requirement along with an incentive sharing mechanism that targets a return of 10.10 per cent on a deemed common equity of 40 per cent, with a possible range of outcomes from 8.70 per cent to 11.50 per cent
- the continued use of a deferral account that compensates for the differences between actual revenues and the fixed toll arrangement, plus an agreement that any overall variance in revenues for the 2015-2020 period is assigned to the eastern area shippers for the period beyond 2020.

Eastern Mainline Project

In October 2014, we filed an application seeking NEB approval to build, own and operate new facilities for our existing Canadian Mainline natural gas transmission system in southeastern Ontario (Eastern Mainline Project). The new facilities are a result of the proposed transfer of a portion of the Canadian Mainline capacity from natural gas service to crude oil service as part of our Energy East Pipeline and an open season that closed in January 2014. The $1.5 billion capital project will add 0.6 Bcf/d of new capacity in the Eastern Triangle segment of the Canadian Mainline and will ensure appropriate levels of capacity are available to meet the requirements of existing shippers as well as new firm service commitments. The project is contingent upon the Energy East Pipeline and is subject to regulatory approvals expected to be issued simultaneously with regulatory approvals for the Energy East Pipeline. The project is expected to be in service by second quarter 2017.

Other Canadian Mainline Expansions

In addition to the Eastern Mainline Project, we have executed new short haul arrangements in the Eastern Triangle portion of the Canadian Mainline that require new facilities, or modifications to existing facilities with a total capital cost of approximately $475 million with expected in-service dates between November 1, 2015 and November 1, 2016. These projects are subject to regulatory approval and, once constructed, will provide capacity needed to meet customer requirements in eastern Canada.

U.S. Pipelines

Sale of Bison Pipeline to TC PipeLines, LP

In October 2014, we closed the sale of our remaining 30 per cent interest in Bison Pipeline LLC to our master limited partnership, TC PipeLines, LP, for cash proceeds of US$215 million.

Sale of GTN Pipeline to TC PipeLines, LP

In November 2014, we announced an offer to sell the remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP. Subject to the satisfactory negotiation of terms and TC PipeLines, LP's board approval, the transaction is expected to close in late first quarter 2015.

At December 31, 2014, we held a 28.3 per cent interest in TC PipeLines, LP for which we are the General Partner.

ANR Pipeline

We have secured nearly 2.0 Bcf/d of firm natural gas transportation commitments for existing and expanded capacity on ANR Pipeline's Southeast Main Line (SEML). The capacity sales and expansion projects include reversing the Lebanon Lateral in western Ohio, additional compression at Sulphur Springs, Indiana, expanding the Rockies Express pipeline interconnect near Shelbyville, Indiana and 600 MMcf/d of capacity as part of a reversal project on the SEML. Capital costs associated with the ANR System expansions required to bring the additional capacity to market are currently estimated to be US$150 million. The capacity was subscribed at maximum rates for an average term of 23 years with approximately 1.25 Bcf/d of new contracts beginning service in late 2014. These secured contracts on the SEML will move Utica and Marcellus shale gas to points north and south on the system.

ANR is also assessing further demand from our customers to transport natural gas from the Utica/Marcellus formation, which is expected to result in incremental opportunities to enhance and expand the system.

Mexican Pipelines

Tamazunchale Pipeline Extension

Construction of the US$600 million extension was completed November 6, 2014. Delays from the original service commencement date of March 9, 2014 were attributed primarily to archeological findings along the pipeline route. Under the terms of the Transportation Service Agreement, these delays were recognized as a force majeure with provisions allowing for collection of revenue from the original service commencement date.

Topolobampo and Mazatlan Pipelines

Permitting, engineering, and construction 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 to Topolobampo, Sinaloa from interconnects with third party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico. 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 CFE and are expected to be in service mid to late 2016.

International Gas Pipelines

Gas Pacifico/INNERGY sale

In November 2014, we closed the sale of our 30 per cent equity interests in Gas Pacifico/INNERGY at a price of $9 million. This sale marks our exit from the Southern Cone region of South America.

LNG Pipeline Projects

Coastal GasLink

In October 2014, the B.C. Environmental Assessment Office issued an Environmental Assessment Certificate (EAC) for Coastal GasLink. In 2014, we also submitted applications to the B.C. Oil and Gas Commission (BC OGC) for the permits required under the Oil and Gas Activities Act to build and operate Coastal GasLink. Regulatory review of those applications is progressing on schedule, with permit decisions anticipated in first quarter 2015. We are currently continuing our engagement with Aboriginal groups and stakeholders along the pipeline route and are progressing detailed engineering and construction planning work to support the regulatory applications and refine the capital cost estimates. Pending the receipt of all required regulatory approvals and a positive FID from our customer, construction is anticipated in 2016, with an in-service date by the end of the decade. Should the project not proceed, our project costs (including AFUDC) are fully recoverable.

Prince Rupert Gas Transmission

On November 25, 2014, we received an EAC from the B.C. Environmental Assessment Office. We have submitted our pipeline permit applications to the BC OGC for construction of the pipeline and anticipate receiving these permits in first quarter 2015.

We have made significant changes to the project route since first announced, increasing it by 150 km (93 miles) to 900 km (559 miles), taking into account Aboriginal and stakeholder input. We continue to work closely with First Nations and stakeholders along the proposed route to create and deliver appropriate benefits to all impacted groups. In October 2014, we concluded a benefits agreement with the Nisga'a First Nation to allow 85 km (52 miles) of the proposed natural gas pipeline to run through Nisga'a Lands.

On December 3, 2014, our customer announced the deferral of an FID. We continue to work with our contractors to refine capital cost estimates for the project. Once the permitting process with the BC OGC is complete and Pacific NorthWest LNG secures the necessary regulatory approvals and proceeds with a positive FID, we will be in a position to begin construction. All costs would be fully recoverable should the project not proceed. The deferral of an FID past the end of 2014 has resulted in a deferral of the expected in-service date for the pipeline. The in-service date will depend on when our customer receives the necessary regulatory approvals and is in a position to make an FID.

Alaska

In April 2014, the State of Alaska passed new legislation to provide a framework for us, the three major Alaska North Slope producers (ANS Producers), and the Alaska Gasline Development Corp. (AGDC) to advance the development of an LNG export project, which is believed to be the best opportunity to commercialize Alaska North Slope gas resources in current market conditions. In June 2014, we executed an agreement with the State of Alaska to abandon the previous project governance and framework and executed a new precedent agreement where we will act as the transporter of the State's portion of natural gas under a long-term shipping contract in the Alaska LNG Project. We also entered into a Joint Venture Agreement with the three major ANS Producers and AGDC to commence the pre-front end engineering and design (pre-FEED) phase of Alaska LNG Project. The pre-FEED work is anticipated to take two years to complete with our share of the cost to be approximately US$100 million. The precedent agreement also provides us with full recovery of development costs in the event the project does not proceed.

In July 2014, the ANS Producers filed an export permit application with the U.S. Department of Energy for the right to export 20 million tonnes per annum of liquefied natural gas for 30 years. In September 2014, the FERC approved the National Environmental Policy Act (NEPA) pre-file request jointly made by us, the three major ANS Producers and AGDC. This approval triggers the NEPA environmental review process, which includes a series of community consultations.

BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 99 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.

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. We continue to monitor changes in the capital programs of our customers and how these changes may impact our project schedules.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 the amount actually produced depends 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

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 and the avoidance of bypass pipelines 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 that 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.

Commodity Prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure. As well, sustained low gas prices could impact our shippers' financial situation and their ability to meet their transportation service cost obligations.

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 and therefore could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion of our 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 income 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.

Liquids Pipelines

Our existing liquids pipeline infrastructure connects Alberta and U.S. 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. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, expand Canadian and U.S. crude oil to U.S. markets and connect condensate supplies to U.S. and Canadian markets.

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 liquids supply to key markets, and are planning to expand our liquids transportation infrastructure to deliver supply directly from producing regions seamlessly along a contiguous path to the market.

We see the potential for expanding transportation service offerings to other areas of the liquids pipelines value chain such as condensate transportation or ancillary services such as short and long-term storage of liquids, which complement our pipeline transportation infrastructure.

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


Liquids Pipelines
Existing
In Development
Under Construction
Crude Oil Terminal
35
31
30
34
29
36
37
32
33
25
26
27
28
500 km
200 mi
N
TC - 01 - 15

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

		length	description	ownership
	Liquids pipelines			
25	Keystone Pipeline System	4,247 km (2,639 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka Illinois, Cushing, Oklahoma, and Port Arthur, Texas	100%
26	Cushing Marketlink		Transports crude oil from the market hub at Cushing, Oklahoma to the Port Arthur, Texas refining market on facilities that form part of the Keystone Pipeline System	100%
	Under construction			
27 28	Houston Lateral and Houston Terminal	77 km (48 miles)	To extend the Keystone Pipeline System to the Houston, Texas refining market	100%
29	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
30	Grand Rapids Pipeline	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
31	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%
	In development			
32	Bakken Marketlink		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%
33	Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
34 35	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%
36	Energy East Pipeline	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
37	Upland Pipeline	460 km (285 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with the Energy East Pipeline at Moosomin, Saskatchewan	100%

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable EBITDA	**1,059**	752	698
Comparable depreciation and amortization	**(216)**	(149)	(145)
Comparable EBIT	**843**	603	553
Specific items	**–**	–	–
Segmented earnings	**843**	603	553

Liquids Pipelines segmented earnings were $240 million higher in 2014 than in 2013 and $50 million higher in 2013 than in 2012. Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Keystone Pipeline System	**1,073**	766	712
Liquids Pipelines Business Development	**(14)**	(14)	(14)
Liquids Pipelines – comparable EBITDA	**1,059**	752	698
Comparable depreciation and amortization	**(216)**	(149)	(145)
Liquids Pipelines – comparable EBIT	**843**	603	553
Comparable EBIT denominated as follows			
Canadian dollars	**215**	201	191
U.S. dollars	**570**	389	363
Foreign exchange impact	**58**	13	(1)
Liquids Pipelines – comparable EBIT	**843**	603	553

Comparable EBITDA

Comparable EBITDA for the Keystone Pipeline System was $307 million higher this year than in 2013. This increase was primarily due to:

- incremental earnings from the Keystone Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for the Keystone Pipeline System was $54 million higher in 2013 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
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable depreciation and amortization

Comparable depreciation and amortization was $67 million higher in 2014 than in 2013 due to the Keystone Gulf Coast extension being placed in service.

OUTLOOK

Earnings

Our 2015 earnings are not expected to be significantly different than our 2014 earnings. We continue to seek further operational efficiencies which would, depending on market demand, improve capacity and flows on the Keystone Pipeline System.

Over time, Liquids Pipelines' earnings will increase as projects currently in development are placed in service.

Capital spending

We spent a total of $2.0 billion in 2014 on capital spending in Liquids Pipelines. We expect to spend approximately $2.3 billion on capital spending and equity investments in 2015, primarily on Grand Rapids, Northern Courier, Energy East and Heartland. See page 105 for further discussion on liquidity risk.

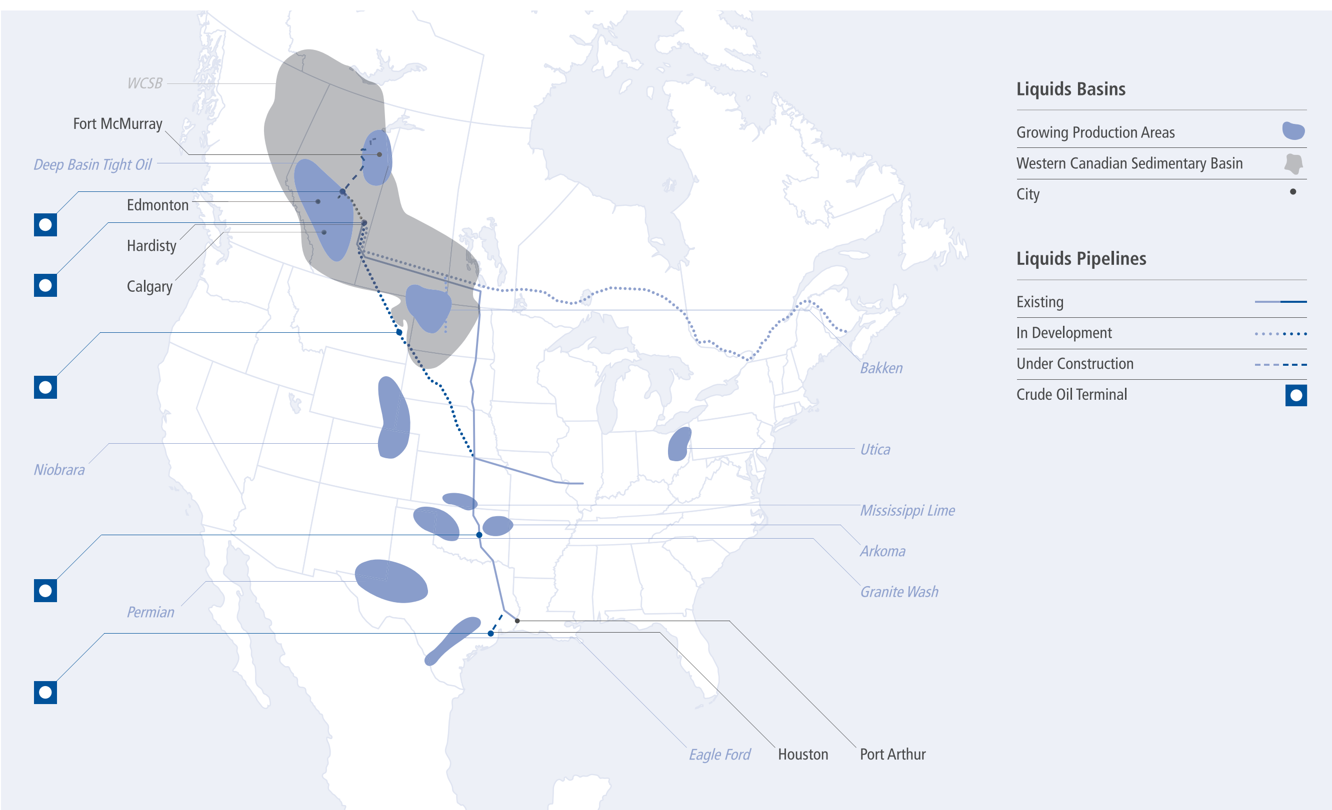
UNDERSTANDING THE LIQUIDS PIPELINES BUSINESS

In general, 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 liquids 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 and strategic priorities



Over the past decade, North American crude oil production has increased significantly in response to growth in global energy consumption and increased demand for crude oil. This growth in crude oil supply has increased the demand for new liquids pipeline infrastructure to connect these supplies to key North American and overseas markets. We have successfully secured a $25 billion portfolio of commercially secured projects to develop this infrastructure and we continue to pursue additional opportunities to expand our transportation service offerings to other areas of the value chain such as the long-term storage of liquids.

Recently, crude oil prices have declined sharply as continued growth in U.S. light oil supply, which has displaced North American imports, and growth in other global supplies has outpaced incremental demand. Although supplies from high cost production may be reduced if lower prices persist, our business is not expected to be significantly impacted by commodity price changes or supply reductions. Our existing operations and development projects are supported by long-term contracts where we have agreed to provide pipeline capacity to our customers in exchange for fixed monthly payments. The cyclical supply and demand nature of commodities and its price movements can have a secondary impact on our business where our shippers may choose to accelerate or delay certain new projects. This can impact the timing for the demand of transportation services and/or new liquids pipeline infrastructure.

Commodity price fluctuations are a normal part of the business cycle. Longer-term, we expect global demand for crude oil will continue to grow resulting in continued growth in North American crude oil supply production and demand for new pipeline infrastructure. Our growing position in the crude oil transportation business is creating a significant platform to capture these future growth opportunities.

Supply outlook

Canada

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 its 2014 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) estimated 2015 WCSB crude oil production of 1.4 million Bbl/d of conventional crude oil and condensate and 2.2 million Bbl/d of oil sands crude oil, a total of approximately 3.6 million Bbl/d. The report forecasted WCSB crude oil production will increase to 4.6 million Bbl/d by 2020 and to 6.4 million Bbl/d by 2030.

In a January 2015 press release, CAPP announced estimated 2015 industry capital spending in western Canada, including oil sands development, would decline to $46 billion, $23 billion lower than forecasted in 2014. CAPP forecasts a slowing in the growth of crude oil production from the 2014 Crude Oil Forecast, Markets and Transportation report by 65,000 Bbl/d in 2015 and 120,000 Bbl/d in 2016. Although CAPP anticipates a decrease in capital spending, the revised forecast for total western Canadian crude oil production is approximately 150,000 higher in 2015 than in 2014.

According to the May 2014 *Alberta's Energy Reserves 2013 and Supply/Demand Outlook 2014-2023*, the Alberta Energy Regulator (AER) estimated there is approximately 167 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta. Oil sands projects have a long reserve life. It is estimated that a typical oil sands mine has a 25 to 50 year lifespan, while an in-situ operation will run 10 to 15 years on average. This longevity aligns with the producer's desire to secure long-term connectivity of their reserves to market. The Keystone Pipeline System, including Keystone XL, and the proposed Energy East Pipeline are underpinned by long term contracts.

U.S.

According to the International Energy Agency World Energy Outlook 2014 Report, by 2020 the U.S. is set to surpass Saudi Arabia as the world's largest crude oil producer. The U.S. Energy Information Administration (EIA) projects over 1.0 million Bbl/d of U.S. production growth from 2014 to 2019, peaking at 9.6 million Bbl/d by 2019. Higher production volumes are mainly a result of recent advancements in shale oil production. EIA forecasts shale oil production peaking at approximately 4.8 million Bbl/d by 2020 and declining after 2022.

U.S. shale oil supply growth is mainly originating 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 also represent some of the sources of crude oil supply for our Bakken Marketlink 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. Cushing Marketlink, which use facilities that form part of the Keystone Pipeline System, provides 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 these refineries are mainly configured to process heavy and medium 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.

Strategic priorities

We are focused on advancing our current portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets.

Securing regulatory approval for our $12 billion Energy East Pipeline is a key priority. In 2014, we filed necessary regulatory applications for approval to construct and operate this project and we are actively engaged with stakeholders as we work towards securing regulatory approval. Refineries in eastern Canada currently process primarily light crude oil imported from west Africa and the Middle East, and therefore could process North American light crude oil. According to the 2014 *Crude Oil Forecast, Markets and Transportation* report, total refining capacity in eastern Canada is approximately 1.2 million Bbl/d, and western Canada supplied only 354,000 Bbl/d to these eastern refineries. Due to insufficient pipeline capacity, many of these refineries have begun receiving 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, once approved and constructed, will meet this demand.

We also remain fully committed to Keystone XL despite the unprecedented regulatory delays we have faced on this project. Keystone XL would expand the Keystone Pipeline System to provide more than 800,000 Bbl/d of additional capacity. This project is supported by long-term contracts and will transport crude oil from Canada as well as growing U.S. crude oil supplies to the large refining markets found in the American Midwest and along the U.S. Gulf Coast.

Within Alberta, we are leveraging our extensive natural gas pipeline footprint and experience to develop a regional liquids pipeline business. Growth in oil sands production is 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 as well as diluent from Edmonton/Heartland region to the production area in northern Alberta. The Heartland Pipeline and TC Terminals projects are intended to support these market hubs which will allow shippers the ability to connect with the Keystone Pipeline System, Energy East Pipeline and other pipelines that transport crude oil outside of Alberta to ultimately provide our customers with a contiguous seamless path from production to market.

As our liquids pipeline footprint continues to grow throughout North America, we are also pursuing other opportunities to expand our service offerings.These opportunities also include the development of rail transportation solutions, transportation of other liquids such as condensate, and the addition of terminal and liquids storage services to complement our existing infrastructure.

SIGNIFICANT EVENTS

Keystone Pipeline System

The completion of the Gulf Coast extension in January 2014 expanded the Keystone Pipeline System to a 4,247 km (2,639 miles) pipeline system that transports crude oil from Hardisty, Alberta, to markets in the U.S. Midwest and the U.S. Gulf Coast.

To date, the Keystone Pipeline System has delivered more than 830 million barrels of crude oil from Canada to the U.S.

Cushing Marketlink

Construction was completed on the Cushing Marketlink facilities at Cushing, Oklahoma in September 2014. Cushing Marketlink transports 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.

Houston Lateral and Terminal

Construction continues on the 77 km (48 miles) Houston Lateral pipeline and tank terminal which will extend the Keystone Pipeline System to Houston, Texas refineries. 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 the second half of 2015.

Keystone XL

In January 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. In April 2014, the DOS announced that the national interest determination period has been extended indefinitely to allow them to consider the potential impact of the case discussed below on the Nebraska portion of the pipeline route.

In February 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 Keystone XL. Nebraska's Attorney General filed an appeal which was heard by the Nebraska State Supreme Court on September 5, 2014. On January 9, 2015, the Nebraska State Supreme Court vacated the lower court's ruling that the law was unconstitutional. As a result, the Governor's January 2013 approval of the alternate route through Nebraska for Keystone XL remains valid. Landowners have filed lawsuits in two Nebraska counties seeking to enjoin Keystone XL from condemning easements on state constitutional grounds.

In September 2014, we filed a certification petition for Keystone XL with the South Dakota Public Utilities Commission (PUC). This certification confirms that the conditions under which Keystone XL's original June 2010 PUC construction permit was granted continue to be satisfied. The formal hearing for the certification is scheduled for May 2015.

On January 16, 2015, the DOS reinitiated the national interest review and requested the eight federal agencies, with a role in the review, to complete their consideration of whether Keystone XL serves the national interest and to provide their views to the DOS by February 2, 2015.

On February 2, 2015, the U.S. Environmental Protection Agency (EPA) posted a comment letter to its website suggesting that, among other things, the FSEIS issued by the DOS has not fully and completely assessed the environmental impacts of Keystone XL and that, at lower oil prices, Keystone XL may increase the rates of oil sands production and greenhouse gas emissions. On February 10, 2015, we sent a letter to the DOS refuting these and other comments in the EPA letter but also offering to work with the DOS to ensure it has all the relevant information to allow it to reach a decision to approve Keystone XL.

The timing and ultimate approval of Keystone XL remain uncertain. In the event the project does not proceed as planned, we would reassess and reduce its carrying value to its recoverable amount if necessary and appropriate.

The estimated capital costs for Keystone XL are expected to be approximately US$8.0 billion. As of December 31, 2014, we have invested US$2.4 billion in the project and have also capitalized interest in the amount of US$0.4 billion.

Keystone Hardisty Terminal

The Keystone Hardisty Terminal will be constructed in conjunction with Keystone XL and is expected to be completed approximately two years from the date the Keystone XL permit is received.

Energy East Pipeline

In March 2014, we filed the project description for the Energy East Pipeline with the NEB. This was the first formal step in the regulatory process to receive the necessary approvals to build and operate the pipeline.

On October 30, 2014, we filed the necessary regulatory applications for approvals to construct and operate the Energy East Pipeline and terminal facilities with the NEB. 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 by the end of 2018.

The Energy East Pipeline includes a proposed marine terminal near Cacouna, Québec which would be adjacent to a beluga whale habitat. On December 8, 2014, the Committee on the Status of Endangered Wildlife in Canada recommended that beluga whales be placed on the endangered species list. As a result, we have made the decision to halt any further work at Cacouna and will be analyzing the recommendation, assessing any impacts to the project and reviewing all viable options. We intend to make a decision on how to proceed by the end of first quarter 2015.

The 1.1 million Bbl/d Energy East Pipeline received approximately one million Bbl/d of firm, long-term contracts to transport crude oil from western Canada that were secured during binding open seasons.

Northern Courier Pipeline

In July 2014, the AER issued a permit approving our application to construct and operate the Northern Courier Pipeline. Construction has started on the $900 million, 90 km (56 miles) pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. We currently expect the pipeline to be ready for service in 2017.

Heartland Pipeline and TC Terminals

The Heartland Pipeline is a 200 km (125 miles) crude oil pipeline connecting the Edmonton/Heartland, Alberta market region to facilities in Hardisty, Alberta. TC Terminals is a terminal facility in the Heartland industrial area north of Edmonton, Alberta.

The pipeline could transport up to 900,000 Bbl/d, while the terminal is expected to have initial storage capacity for up to 1.9 million barrels of crude oil. In February 2014, the application for the terminal facility was approved and construction commenced in October 2014.

These projects together have a combined estimated cost of $900 million and are expected to be placed in service in late 2017.

Grand Rapids Pipeline

On October 9, 2014, the AER issued a permit approving our application to construct and operate the Grand Rapids Pipeline. We have a partner through a joint venture, to develop Grand Rapids, a 460 km (287 miles) crude oil and diluent pipeline system connecting the producing area northwest of Fort McMurray, Alberta to terminals in the Edmonton/Heartland, Alberta region. Each partner will own 50 per cent of the $3 billion pipeline project, and we will be the operator. Our partner has also entered into a long-term transportation service contract in support of Grand Rapids. Construction has commenced with initial crude oil transportation planned in 2016.

Upland Pipeline

In November 2014, we completed a successful binding open season for the Upland Pipeline. The $600 million pipeline would provide crude oil transportation from, and between multiple points in North Dakota and interconnect with the Energy East Pipeline System at Moosomin, Saskatchewan.

Subject to regulatory approvals, we anticipate the Upland Pipeline to be in service in 2018. The commercial contracts we have executed for Upland Pipeline are conditioned on Energy East proceeding.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 99 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 liquids pipelines is essential to the success of our liquids 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 liquids 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 lobbying against the construction of liquids pipelines. We manage this risk by continuously monitoring regulatory developments and decisions to determine their possible impact on our liquids 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

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Lower prices for crude oil could mean producers may curtail their investment in the further 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, to re-contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American liquids 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 approximately 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 power business in the U.S. 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 and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total 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 over 350 Bcf of natural gas storage and related services.

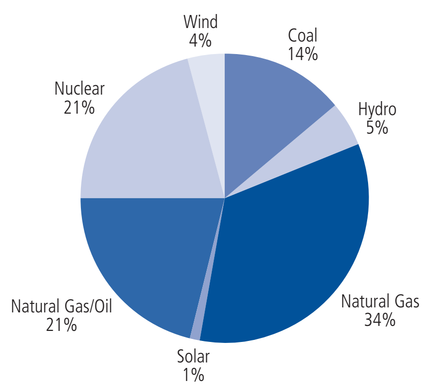
Strategy at a glance

We are focusing on growing a portfolio of low-cost, long-life power generation and natural gas storage assets located in core North American markets, while maximizing the value of our existing investments through safe and reliable operations.

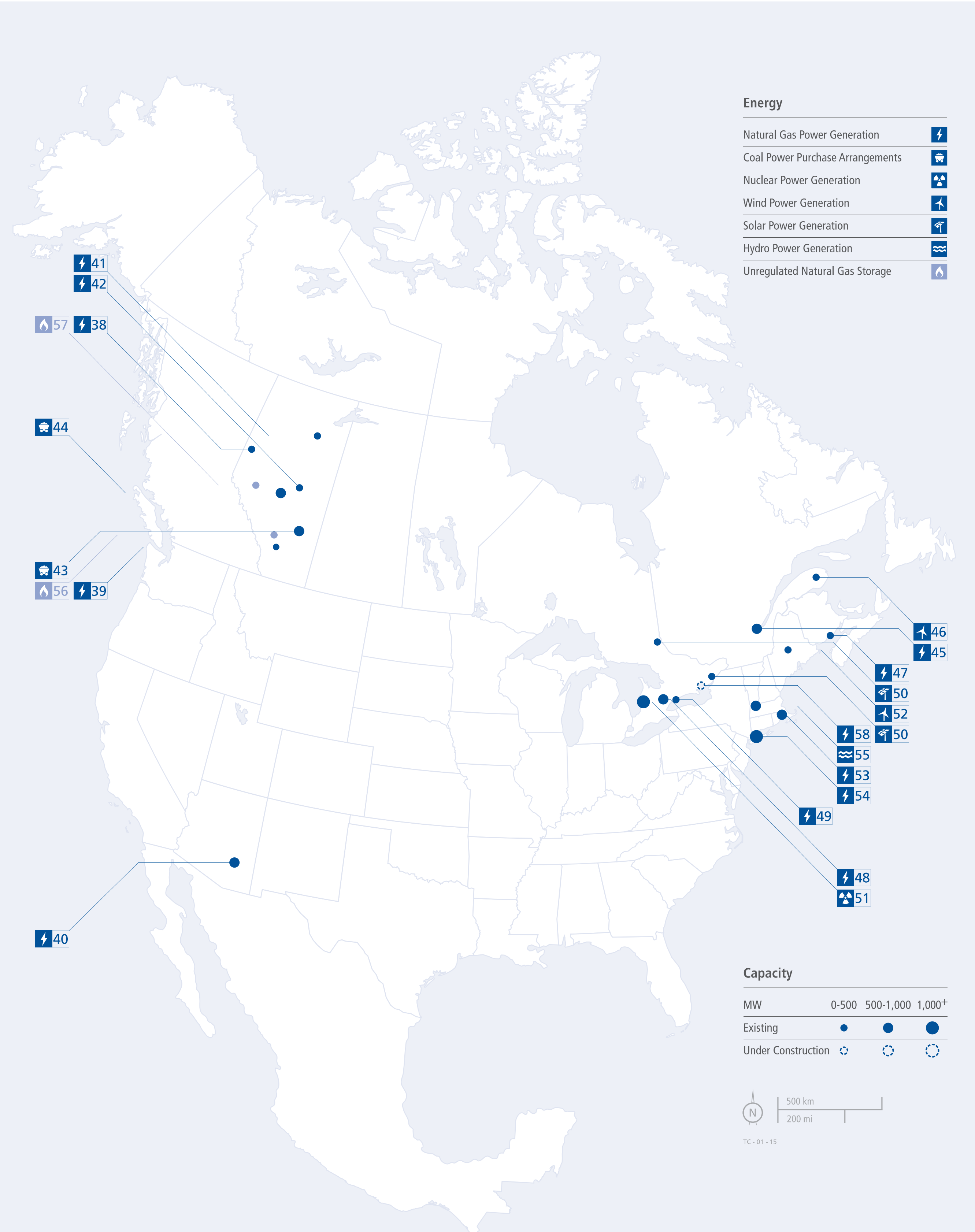
Growth opportunities in the North American power generation sector are arising from increasing demand for power and the need to replace aging power generation infrastructure with gas-fired and renewable generation plants as societal trends and policies continue to focus on lowering the carbon intensity of the generation fleet. We are well positioned to participate in the development of this new power generation infrastructure due to our strong presence and experience in core markets and the strategic locations of existing operations. Our recent investments in solar generation and the construction of the Napanee Generating Station in Ontario, both of which are underpinned with long-term contracts, are examples of such growth and opportunity. The potential for further nuclear refurbishment at Bruce Power is another example of the opportunities for us to further develop our diverse portfolio of generation technologies, fuel types, markets and contract structures.

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 and from the addition of LNG export terminals. In the long-term, we expect an increased dependence on natural gas storage will drive higher returns from our gas storage operations.

Power by Fuel Source[1]



[1] Includes facilities under construction.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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
Under Construction
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500 km
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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 8,037 MW of power generation capacity (including facilities under construction)					
	Western Power 2,609 MW of power supply in Alberta and the western U.S.					
38	Bear Creek	80	natural gas	Cogeneration plant	Grande Prairie, Alberta	100%
39	Carseland	80	natural gas	Cogeneration plant	Carseland, Alberta	100%
40	Coolidge[1]	575	natural gas	Simple-cycle peaking facility	Coolidge, Arizona	100%
41	Mackay River	165	natural gas	Cogeneration plant	Fort McMurray, Alberta	100%
42	Redwater	40	natural gas	Cogeneration plant	Redwater, Alberta	100%
43	Sheerness PPA	756	coal	Output contracted under PPA	Hanna, Alberta	100%
44	Sundance A PPA	560	coal	Output contracted under PPA	Wabamun, Alberta	100%
44	Sundance B PPA (Owned by ASTC Power Partnership[2])	353[3]	coal	Output contracted under PPA	Wabamun, Alberta	50%
	Eastern Power 2,939 MW of power generation capacity (including facilities under construction)					
45	Bécancour	550	natural gas	Cogeneration plant	Trois-Rivières, Québec	100%
46	Cartier Wind	365[3]	wind	Five wind power projects	Gaspésie, Québec	62%
47	Grandview	90	natural gas	Cogeneration plant	Saint John, New Brunswick	100%
48	Halton Hills	683	natural gas	Combined-cycle plant	Halton Hills, Ontario	100%
49	Portlands Energy	275[3]	natural gas	Combined-cycle plant	Toronto, Ontario	50%
50	Ontario Solar	76	solar	Eight solar facilities	Southern Ontario and New Liskeard, Ontario	100%
	Bruce Power 2,489 MW of power generation capacity through eight nuclear power units					
51	Bruce A	1,467[3]	nuclear	Four operating reactors	Tiverton, Ontario	48.9%
51	Bruce B	1,022[3]	nuclear	Four operating reactors	Tiverton, Ontario	31.6%

	generating capacity (MW)	type of fuel	description	location	ownership
U.S. Power 3,755 MW of power generation capacity					
52 Kibby Wind	132	wind	Wind farm	Kibby and Skinner Townships, Maine	100%
53 Ocean State Power	560	natural gas	Combined-cycle plant	Burrillville, Rhode Island	100%
54 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%
55 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					
56 CrossAlta	68 Bcf		Underground facility connected to the NGTL System	Crossfield, Alberta	100%
57 Edson	50 Bcf		Underground facility connected to the NGTL System	Edson, Alberta	100%
Under construction					
58 Napanee	900	natural gas	Combined-cycle plant	Greater Napanee, Ontario	100%

1 Located in Arizona, results reported in Canadian Power – Western Power.
2 We have a 50 per cent interest in ASTC Power Partnership, which has a PPA for production from the Sundance B power generating facilities.
3 Our share of power generation capacity.

RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure).

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable EBITDA	**1,348**	1,363	903
Comparable depreciation and amortization	**(309)**	(294)	(283)
Comparable EBIT	**1,039**	1,069	620
Specific items:			
Cancarb gain on sale	**108**	-	-
Niska contract termination	**(43)**	-	-
Sundance A PPA arbitration decision – 2011	**-**	-	(20)
Risk management activities	**(53)**	44	(21)
Segmented earnings	**1,051**	1,113	579

Energy segmented earnings were $62 million lower in 2014 than in 2013 and $534 million higher in 2013 than in 2012.

Energy segmented earnings included the following specific items:

- a gain of $108 million on the sale of Cancarb Limited and its related power generation business, which closed in April 2014
- a net loss of $43 million resulting from the contract termination payment to Niska Gas Storage effective April 30, 2014
- a net loss of $20 million resulting from the Sundance A PPA arbitration decision in July 2012 related to 2011
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities (millions of $, pre-tax)	**2014**	**2013**	**2012**
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Total (losses)/gains from risk management activities	**(53)**	44	(21)

The year over year variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our position for these particular derivatives over a certain period of time; however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them part of our underlying operations.

The specific items noted above have been excluded in our calculation of comparable EBIT. The remainder of the Energy segmented earnings are equivalent to comparable EBIT, which along with comparable EBITDA, are discussed below.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Canadian Power			
Western Power	**252**	355	311
Eastern Power[1]	**350**	322	321
Bruce Power	**314**	310	14
Canadian Power – comparable EBITDA[2]	**916**	987	646
Comparable depreciation and amortization	**(179)**	(172)	(152)
Canadian Power – comparable EBIT[2]	**737**	815	494
U.S. Power (US$)			
U.S. Power – comparable EBITDA	**376**	323	209
Comparable depreciation and amortization	**(107)**	(107)	(121)
U.S. Power – comparable EBIT	**269**	216	88
Foreign exchange impact	**27**	7	-
U.S. Power – comparable EBIT (Cdn$)	**296**	223	88
Natural Gas Storage and other			
Natural Gas Storage and other – comparable EBITDA[2]	**44**	63	67
Comparable depreciation and amortization	**(12)**	(12)	(10)
Natural Gas Storage and other – comparable EBIT[2]	**32**	51	57
Business Development comparable EBITDA and EBIT	**(26)**	(20)	(19)
Energy – comparable EBIT[2]	**1,039**	1,069	620
Summary			
Energy – comparable EBITDA[2]	**1,348**	1,363	903
Comparable depreciation and amortization	**(309)**	(294)	(283)
Energy – comparable EBIT[2]	**1,039**	1,069	620

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.

2 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 $15 million lower in 2014 than in 2013. The decrease was the effect of:

- lower earnings from Western Power due to lower realized prices
- higher earnings from U.S. Power mainly because of higher realized capacity prices in New York and higher realized power prices at our New York and New England facilities
- incremental earnings from Eastern Power primarily due to four solar facilities acquired in each of 2013 and 2014
- lower earnings from Natural Gas Storage due to lower realized natural gas storage price spreads.

Comparable EBITDA for Energy was $460 million higher in 2013 compared to 2012. This 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 as well as 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.

OUTLOOK

Earnings

We expect 2015 earnings from the Energy segment to be slightly lower than 2014, assuming the net effect of the following expectations:

- lower power prices in Alberta
- lower Bruce Power equity income due to increased planned maintenance activity and higher operating costs
- lower contributions from our Natural Gas Storage operations
- lower earnings as a result of the sale of Cancarb in April 2014
- lower realized capacity prices in New York
- higher contributions from U.S. Power assets due to increased net energy margins and production
- a full year of earnings from Ontario solar facilities acquired in 2014
- higher contributions from our power operations in Québec.

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 and can drive fluctuations in our Energy results.

Western Power

2015 average spot power prices are expected to be slightly lower than 2014. The Alberta power market was relatively well supplied in 2014 and that trend is expected to be further entrenched in 2015 with the addition of a large gas-fired power plant in the Calgary area which is expected to be placed in service in first half 2015. Average spot market power prices in 2014 ($50/MWh) were much lower than 2013 ($80/MWh) primarily due to strong coal fleet availability and new wind generation capacity despite strong annual power demand growth of just over three per cent.

The Alberta Electric System Operator is forecasting healthy supply growth over the next 10 years in order to meet continued demand growth of over three per cent per year over the next 10 years. While some of this robust growth outlook in Alberta is underpinned by oil and gas activity and demand, it is also driven by the anticipated coal fleet turnover and need to replace other aging generation capacity being retired over time. We remain cautiously optimistic that the Alberta market will continue to outpace growth in other regions of North America.

Natural Gas Storage

Natural gas price spreads are expected to modestly improve from cyclical lows, however, extreme gas price volatility experienced in first quarter 2014 is not expected to repeat in first quarter 2015. As a result, the 2015 segment contribution is expected to be slightly lower compared to 2014 results.

Eastern Power

In January 2015, the OPA and the Independent Electricity System Operator (IESO) merged and now operate as one organization which is continuing under the name IESO. This merger does not impact the terms of any of our contracts with the OPA.

All of our energy assets in eastern Canada are fully contracted. The Ontario assets are contracted with the IESO and are largely sheltered from spot market pricing. Eastern Power earnings in 2015 are expected to be higher as a result of a full year of operations from the additional solar assets acquired in 2014 as well as higher contractual earnings at Bécancour.

The Ontario power market is currently well supplied despite the fact that the coal-fired fleet is now fully retired. The combination of flat system demand growth, partly due to conservation programs and increased nuclear and renewable output, is enabling Ontario to be a net exporter of electricity.

Bruce Power

We expect 2015 equity income from Bruce Power to be lower than 2014 primarily due to increased planned maintenance activity and higher costs at each of Bruce A and Bruce B. During second quarter 2015, all Bruce B units are expected to be removed from service for approximately one month to allow for inspection of the Bruce B vacuum building. The vacuum building is a key component of the site's safety systems and is required to be inspected approximately once every decade. Additional planned maintenance at Bruce B is scheduled to occur during second quarter 2015.

Planned maintenance at Bruce A is scheduled for first and third quarters of 2015.

Overall plant availability percentages in 2015 are expected to be in the mid 80s for Bruce A and Bruce B.

The Ontario government's 2013 Long-Term Energy Plan outlined their intentions on nuclear power's role in the fuel mix going forward. The potential refurbishment of six Bruce Power units was included within the plan and Bruce Power is actively considering the site's refurbishment options within this context.

U.S. Power

U.S. northeast markets experienced a colder than normal winter in 2014 with multiple polar vortex events and natural gas pipeline constraints causing high price volatility in the winter months. However, the summer months experienced below normal temperatures that reduced air conditioning power demand. In 2015, we expect to continue to experience price volatility in the winter months due to pipeline constraints; however, recent reductions in fuel oil prices are anticipated to keep peak price excursions limited compared to previous years. The New York and New England ISO forecasts growth in the demand for power of about one per cent per year in the coming years.

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 as a result are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. New York Spot capacity prices are on average expected to be lower in 2015 than 2014.

The timing of recognizing earnings from our U.S. power marketing business is impacted by different pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased to fulfill our sales obligations over the term of the contracts. The costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers includes the impact of certain contracts to purchase power over multiple periods at a flat price. Because the price we charge our customers is typically shaped to the market, the impact of these two contract pricing profiles has generally resulted in higher earnings in January to March, offset by lower earnings between April and December with overall positive margins over the term of the contracts. Due to increased volatility of forward natural gas and power prices in the New England market, these timing differences will be more significant in 2015.

Capital spending

We spent a total of $0.2 billion in 2014, and expect to spend approximately $0.3 billion on capital spending in Energy in 2015. See page 105 for further discussion on liquidity risk.

Equity investments and acquisitions

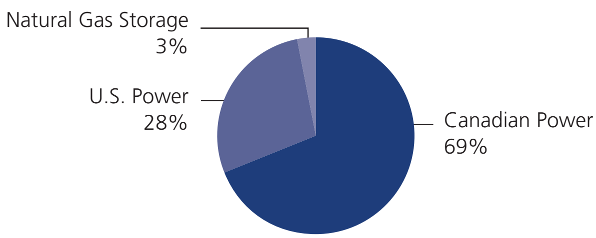
In 2014, we also invested $0.2 billion on the acquisition of four Ontario solar facilities and $0.1 billion in Bruce Power for capital projects. We expect to spend approximately $0.2 billion on Bruce Power investments in 2015.

UNDERSTANDING THE ENERGY BUSINESS

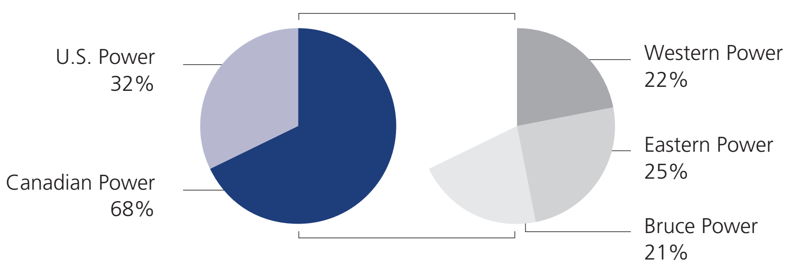
Our Energy business is made up of three groups:

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

Energy comparable EBIT – contribution by group, excluding business development expenses
year ended December 31, 2014



Power generation capacity – contribution by group
year ended December 31, 2014 (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 the 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 to large industrial and commercial companies as well as 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	IESO	2030
Portlands Energy	20-year Clean Energy Supply contract	IESO	2029
Ontario Solar[2]	20-year Feed-in Tariff (FIT) contracts	IESO	2032-2034

1 Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.
2 We acquired four facilities in 2013 and an additional four facilities in 2014.

Assets currently under construction are as follows:

	Type of contract	With	Expires
Napanee	20-year Clean Energy Supply contract	IESO	20 years from in-service date

Western and Eastern Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 24 for more information.

year ended December 31 (millions of $)	2014	2013	2012
Revenue[1]			
Western Power	**736**	605	644
Eastern Power[2]	**428**	400	415
Other[3]	**85**	108	91
	1,249	1,113	1,150
Income from equity investments[4]	**45**	141	68
Commodity purchases resold	**(404)**	(283)	(286)
Plant operating costs and other	**(299)**	(298)	(266)
Sundance A PPA arbitration decision	**-**	-	(30)
Exclude risk management activities[1]	**11**	4	(4)
Comparable EBITDA	**602**	677	632
Comparable depreciation and amortization	**(179)**	(172)	(152)
Comparable EBIT	**423**	505	480
Breakdown of comparable EBITDA			
Western Power	**252**	355	311
Eastern Power	**350**	322	321
Comparable EBITDA	**602**	677	632

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.

3 Includes Revenue from the sale of unused natural gas transportation, sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.

4 Includes our share of equity income from our investments in ASTC Power Partnership, which holds the Sundance B PPA, and Portlands Energy. Equity income does not include any earnings related to our risk management activities.

Sales volumes and plant availability

Includes our share of volumes from our equity investments.

year ended December 31	2014	2013	2012
Sales volumes (GWh)			
Supply			
Generation			
Western Power	**2,517**	2,728	2,691
Eastern Power[1]	**3,080**	3,822	4,384
Purchased			
Sundance A & B and Sheerness PPAs and other[2]	**11,472**	8,223	6,906
Other purchases	**16**	13	46
	17,085	14,786	14,027
Sales			
Contracted			
Western Power	**10,484**	7,864	8,240
Eastern Power[1]	**3,080**	3,822	4,384
Spot			
Western Power	**3,521**	3,100	1,403
	17,085	14,786	14,027
Plant availability[3]			
Western Power[4]	**96%**	95%	96%
Eastern Power[1,5]	**91%**	90%	90%

1 Includes four solar facilities acquired between June and December 2013, three solar facilities acquired in September 2014, and one solar facility acquired in December 2014 and Cartier Wind phase two of Gros-Morne completed in November 2012.
2 Includes our 50 per cent ownership interest of Sundance B volumes through the ASTC Power Partnership. Sundance A Unit 1 returned to service in September 2013 and Unit 2 returned to service in October 2013.
3 The percentage of time in a period that the plant is available to generate power, regardless of whether it is running.
4 Does not include facilities that provide power to us under PPAs.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA in 2014 was $103 million lower than in 2013, due to the net effect of:

- lower realized power prices
- incremental earnings from the return to service of the Sundance A PPA Unit 1 in September 2013 and Unit 2 in October 2013 which also resulted in increased volume purchases
- sale of Cancarb in April 2014.

Average spot market power prices in Alberta decreased by 38% from approximately $80/MWh in 2013 to approximately $50/MWh in 2014. Despite strong power demand growth of just over three per cent, ten of the twelve months of 2014 saw relatively soft price levels as the Alberta power market was well supplied during the year. Weather events in February 2014 and July 2014 tightened the supply demand balance resulting in strong prices during those months. 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.

In 2013, Western Power's comparable EBITDA was $44 million higher than 2012. The increase was mainly due to higher purchased volumes under the PPAs following the return to service of Sundance A Units 1 and 2.

Approximately 75 per cent of Western Power sales volumes were sold under contract in 2014 compared to 72 per cent in 2013 and 85 per cent in 2012.

Eastern Power

Eastern Power's comparable EBITDA in 2014 was $28 million higher than 2013 due to the net effect of incremental earnings from the four solar facilities acquired in 2013, the additional four facilities acquired in late 2014 and higher contractual earnings at Bécancour.

In 2013, Eastern Power's comparable EBITDA was similar to 2012 due to the net effect of incremental earnings from Cartier Wind and from the four solar facilities acquired in 2013 and lower 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 3,300 MW. Bruce B leases the eight nuclear reactors from Ontario Power Generation and subleases Units 1 to 4 to Bruce A.

Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned outages.

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

Bruce A fixed price	Per MWh
April 1, 2014 – March 31, 2015	$71.70
April 1, 2013 – March 31, 2014	$70.99
April 1, 2012 – March 31, 2013	$68.23

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, 2014 – March 31, 2015	$52.86
April 1, 2013 – March 31, 2014	$52.34
April 1, 2012 – March 31, 2013	$51.62

Amounts received under the Bruce B floor price mechanism within a calendar year are subject to repayment if the average spot price in a month exceeds the floor price. The first quarter 2014 average spot price exceeded the floor price; however, spot prices fell below the floor price for the remainder of 2014. As a result, Bruce B recognized annual revenues at the floor price throughout 2014 and amounts received above the floor price in first quarter 2014 were repaid to the IESO in January 2015.

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

The contract also provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered "deemed generation", for which Bruce Power is paid the fixed price, floor price or spot price as applicable under the contract.

Bruce Power results

Our proportionate share

year ended December 31 (millions of $, unless otherwise indicated)	**2014**	2013	2012
Income/(loss) from equity investments[1]			
Bruce A	**209**	202	(149)
Bruce B	**105**	108	163
	314	310	14
Comprised of:			
Revenues	**1,256**	1,258	763
Operating expenses	**(623)**	(618)	(567)
Depreciation and other	**(319)**	(330)	(182)
	314	310	14
Bruce Power – other information			
Plant availability[2]			
Bruce A[3]	**82%**	82%	54%
Bruce B	**90%**	89%	95%
Combined Bruce Power	**86%**	86%	81%
Planned outage days			
Bruce A	**118**	123	336
Bruce B	**127**	140	46
Unplanned outage days			
Bruce A	**123**	63	18
Bruce B	**4**	20	25
Sales volumes (GWh)[1]			
Bruce A[3]	**10,526**	10,458	4,194
Bruce B	**8,197**	8,010	8,598
	18,723	18,468	12,792
Realized sales price per MWh[4]			
Bruce A	**$72**	$70	$68
Bruce B	**$56**	$54	$55
Combined Bruce Power	**$63**	$62	$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 include 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 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 2014 was $7 million higher than 2013. The increase was mainly due to lower depreciation and operating expenses and higher volumes partially offset by recognition of an insurance recovery of approximately $40 million in the first quarter 2013. The negative impact of increased outage days in 2014 is offset by higher generation levels while operating.

Equity income from Bruce B in 2014 was $3 million lower than 2013. The decrease was mainly due to higher lease expense recognized based on the terms of the lease agreement with Ontario Power Generation, partially offset by higher volumes and lower operating costs resulting from lower outage days.

In 2013, equity income from Bruce A 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.

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

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 for which we get paid.

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 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 also earn additional revenues by bundling power sales with other energy services.

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 24 for more information.

year ended December 31 (millions of US$)	**2014**	**2013**	**2012**
Revenue			
Power[1]	**1,794**	1,587	1,240
Capacity	**362**	295	234
	2,156	1,882	1,474
Commodity purchases resold	**(1,297)**	(1,003)	(765)
Plant operating costs and other[2]	**(529)**	(509)	(500)
Exclude risk management activities[1]	**46**	(47)	-
Comparable EBITDA	**376**	323	209
Comparable depreciation and amortization	**(107)**	(107)	(121)
Comparable EBIT	**269**	216	88

1 The realized and unrealized gains and losses from financial derivatives used to manage U.S. Power's assets are presented on a net basis in power revenues. The unrealized gains and losses from financial derivatives included in Revenue are excluded to arrive at Comparable EBITDA.

2 Includes the costs of fuel consumed in generation.

Sales volumes and plant availability

year ended December 31	**2014**	**2013**	**2012**
Physical sales volumes (GWh)			
Supply			
Generation	**7,742**	6,173	7,567
Purchased	**10,822**	9,001	9,408
	18,564	15,174	16,975
Plant availability[1]	**82%**	84%	85%

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

U.S. Power – other information

year ended December 31	**2014**	**2013**	**2012**
Average Spot Power Prices (US$ per MWh)			
New England	**65**	57	36
New York	**58**	52	39
Average New York Zone J Spot Capacity Prices (US$ per KW-M)	**14**	11	8

U.S. Power's comparable EBITDA in 2014 was US$53 million higher than 2013. This reflected the net effect of:

- higher realized capacity prices primarily in New York
- higher realized power prices for the New England and New York facilities
- higher generation volumes primarily at the Ravenswood facility
- higher prices and related costs on increased volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers.

In 2013, U.S. Power's comparable EBITDA 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.

Average New York Zone J spot capacity prices were approximately 27 per cent higher in 2014 than in 2013. The increase in spot prices and the impact of hedging activities resulted in higher realized capacity prices in New York in 2014.

Wholesale electricity prices in New York and New England were higher in 2014 compared to 2013 primarily due to colder winter temperatures and gas transmission constraints. This resulted in higher natural gas prices in the predominantly gas-fired New England and New York power markets in first quarter 2014 compared to the same period in 2013. Average spot power prices in 2014 in New England increased approximately 14 per cent and in New York spot power prices increased approximately 11 per cent compared to 2013.

Physical sales volumes in 2014 rose compared to 2013. Generation volumes increased primarily due to higher generation at the Ravenswood facility throughout 2014 compared to 2013. Purchased volumes were also higher in 2014 compared to 2013 due to increased sales to commercial and industrial customers in both the New England and PJM markets.

As at December 31, 2014, approximately 3,700 GWh or 30 per cent of U.S. Power's planned generation is contracted for 2015, and 1,600 GWh or 14 per cent for 2016. 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 and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. 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, 2014	Working gas storage capacity (Bcf)	Maximum injection/ withdrawal capacity (MMcf/d)
Edson	50	725
CrossAlta	68	550
	118	1,275

We also hold a contract for Alberta-based storage capacity with a third party.

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.

Our gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide gas storage services on a short, medium, and/or long term basis.

We also enter into proprietary natural gas storage transactions, which include a forward purchase of our own 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 changes in gas prices.

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 in 2014 was $19 million lower than 2013, mainly due to decreased third party storage revenue as a result of lower realized natural gas storage price spreads.

In 2013, comparable EBITDA 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.

SIGNIFICANT EVENTS

Canadian Power

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, we completed the acquisition of three Ontario solar facilities for $181 million in September 2014 and acquired a fourth facility for $60 million in December 2014. In 2013, we completed the acquisition of four solar facilities for $216 million. Our total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year FIT contracts with the IESO.

Napanee

In January 2015, we began construction activities of a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. 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. Production from the facility is fully contracted with the IESO.

Bécancour

In May 2014, Hydro-Québec exercised its option in the amended suspension agreement to extend suspension of all electricity generation to the end of 2017, and requested further suspension of generation to the end of 2018. Under the December 2013 amended suspension agreement, Hydro-Québec has the option each year to further extend the suspension by an additional year (subject to certain conditions). We continue to receive capacity payments while generation is suspended.

Cancarb Limited and Cancarb Waste Heat Facility

The sale of Cancarb Limited, a thermal carbon black facility, and its related power generation facility closed in April 2014 for gross proceeds of $190 million. We recognized a gain of $99 million, net of tax, in second quarter 2014.

Bruce Power

In March 2014, Cameco Corporation sold 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.

New Canadian federal legislation is expected to come into force in 2015 respecting the determination of liability and compensation for a nuclear incident in Canada resulting in personal injuries and damages. This proposed legislation will replace existing legislation which currently provides that the licensed operator of a nuclear facility has absolute and exclusive liability and limits the liability to a maximum of $75 million. The proposed new law is fundamentally consistent with the existing regime although the maximum liability will increase to $650 million and increase in increments over three years to a maximum of $1 billion. The operator will also be required to maintain financial assurances such as insurance in the amount of the maximum liability. Our indirect subsidiary owns one-third of the shares of Bruce Power Inc., the licensed operator of Bruce Power, and as such Bruce Power is subject to this liability in the event of an incident and the legislation's other requirements.

U.S. Power

Ravenswood

In late September 2014, the 972 MW Unit 30 at the Ravenswood Generating Station experienced an unplanned outage as a result of a problem with the generator associated with the high pressure turbine. Insurance is expected to cover the repair costs and lost revenues associated with the unplanned outage, which are yet to be finalized. As a result of the expected insurance recoveries, net of deductibles, the Unit 30 unplanned outage is not expected to have a significant impact on our earnings although the recording of earnings may not coincide with lost revenues due to timing of the anticipated insurance proceeds. The unit is expected to be back in service in first half 2015.

Natural Gas Storage

Effective April 30, 2014, we terminated a 38 Bcf long-term natural gas storage contract in Alberta with Niska Gas Storage. The contract contained provisions allowing for possible early termination. As a result, we recorded an after tax charge of $32 million in 2014. We have re-contracted for new natural gas storage services in Alberta with Niska Gas Storage starting May 1, 2014 for a six-year period and a reduced average volume.

BUSINESS RISKS

The following are risks specific to our energy business. See page 99 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.

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. In New England and New York, the price of natural gas also has a significant impact on power prices, as energy prices in these markets are usually set by gas-fired power supplies. Extended periods of low gas prices will generally exert downward pressure on power prices and therefore on earnings from our New England and New York 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. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms. 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 IESO, Bruce B volumes are subject to a floor price mechanism. When the spot market price is above the floor price, Bruce B's 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 IESO.

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, and sun-light hours and intensity affects earnings from our solar assets.

Hydrology
Our hydroelectric power generation facilities in the northeastern U.S. are subject to 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.

Competition
We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants in deregulated markets will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies, additional supply from regional power transmission interconnections and new supply in the form of distributed generation. We also face competition from other power companies in the greenfield power plant development arena.

Corporate

OTHER INCOME STATEMENT ITEMS

The following are reconciliations and related analyses of our non-GAAP measures to the equivalent GAAP measures.

Interest expense

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable interest on long-term debt (including interest on junior subordinated notes)			
Canadian dollar-denominated	**(443)**	(495)	(513)
U.S. dollar-denominated	**(854)**	(766)	(740)
Foreign exchange	**(90)**	(20)	-
	(1,387)	(1,281)	(1,253)
Other interest and amortization expense	**(70)**	10	(23)
Capitalized interest	**259**	287	300
Comparable interest expense	**(1,198)**	(984)	(976)
Specific item:			
NEB 2013 Decision – 2012	**-**	(1)	-
Interest expense	**(1,198)**	(985)	(976)

Comparable interest expense in 2014 was $214 million higher than in 2013 due to the net effect of:

- higher interest as a result of long term debt issues of:
  - US$1.25 billion in February 2014
  - 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
- lower interest on account of Canadian and U.S. dollar denominated debt maturities
- higher foreign exchange on interest on U.S. dollar denominated debt
- higher carrying charges to shippers in 2014 on the positive TSA balance for Canadian Mainline
- lower capitalized interest due to the completion of the Gulf Coast extension of the Keystone Pipeline System in first quarter 2014, partially offset by higher capitalized interest primarily for Keystone XL.

Comparable interest expense in 2013 was $8 million higher than 2012 due to the net effect of:

- higher interest as a result of 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
- lower interest on account of Canadian and U.S. dollar denominated debt maturities
- higher foreign exchange on interest on U.S. dollar denominated debt
- lower capitalized interest due to Bruce A Units 1 and 2 return to service in fourth quarter 2012, partially offset by increased capitalized interest on the Gulf Coast extension.

Interest income and other

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable interest income and other	**112**	42	86
Specific items (pre-tax):			
NEB 2013 Decision – 2012	**-**	1	-
Risk management activities	**(21)**	(9)	(1)
Interest income and other	**91**	34	85

Comparable interest income and other in 2014 was $70 million higher than 2013. This was the net result of:

- increased AFUDC related to our rate-regulated projects, including Energy East Pipeline and our Mexico pipelines,
- offset by higher realized losses in 2014 compared to 2013 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

In 2013, comparable interest income and other was $44 million lower than 2012. This decrease was mainly due to higher realized losses in 2013 compared to 2012 on 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.

Income tax expense

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Comparable income tax expense	**(859)**	(662)	(477)
Specific items:			
Cancarb gain on sale	**(9)**	-	-
Niska contract termination	**11**	-	-
Gas Pacifico/INNERGY gain on sale	**(1)**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	5
Risk management activities	**27**	(16)	6
Income tax expense	**(831)**	(611)	(466)

Comparable income tax expense increased $197 million in 2014 compared to 2013 mainly because of higher pre-tax earnings in 2014, changes in the proportion of income earned between Canadian and foreign jurisdictions as well as higher flow-through taxes in 2014 on Canadian regulated pipelines.

Comparable income tax expense increased $185 million in 2013 compared to 2012 because of higher pre-tax earnings in 2013 combined with changes in the proportion of income earned between Canadian and foreign jurisdictions.

Other

year ended December 31 (millions of $)	2014	2013	2012
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Preferred share dividends	**(97)**	(74)	(55)

Net income attributable to non-controlling interests increased by $28 million in 2014 compared to 2013 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013 and the remaining 30 per cent of Bison in October 2014. This was partially offset by the redemption of Series U preferred shares in October 2013 and Series Y preferred shares in March 2014.

Net income attributable to non-controlling interest increased $7 million in 2013 compared to 2012 primarily due to the sale of a 45 per cent interest in each of GTN and Bison to TC PipeLines, LP in July 2013.

Preferred share dividends increased by $23 million in 2014 compared to 2013 due to the issuances of Series 7 preferred shares in March 2013 and Series 9 preferred shares in January 2014.

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

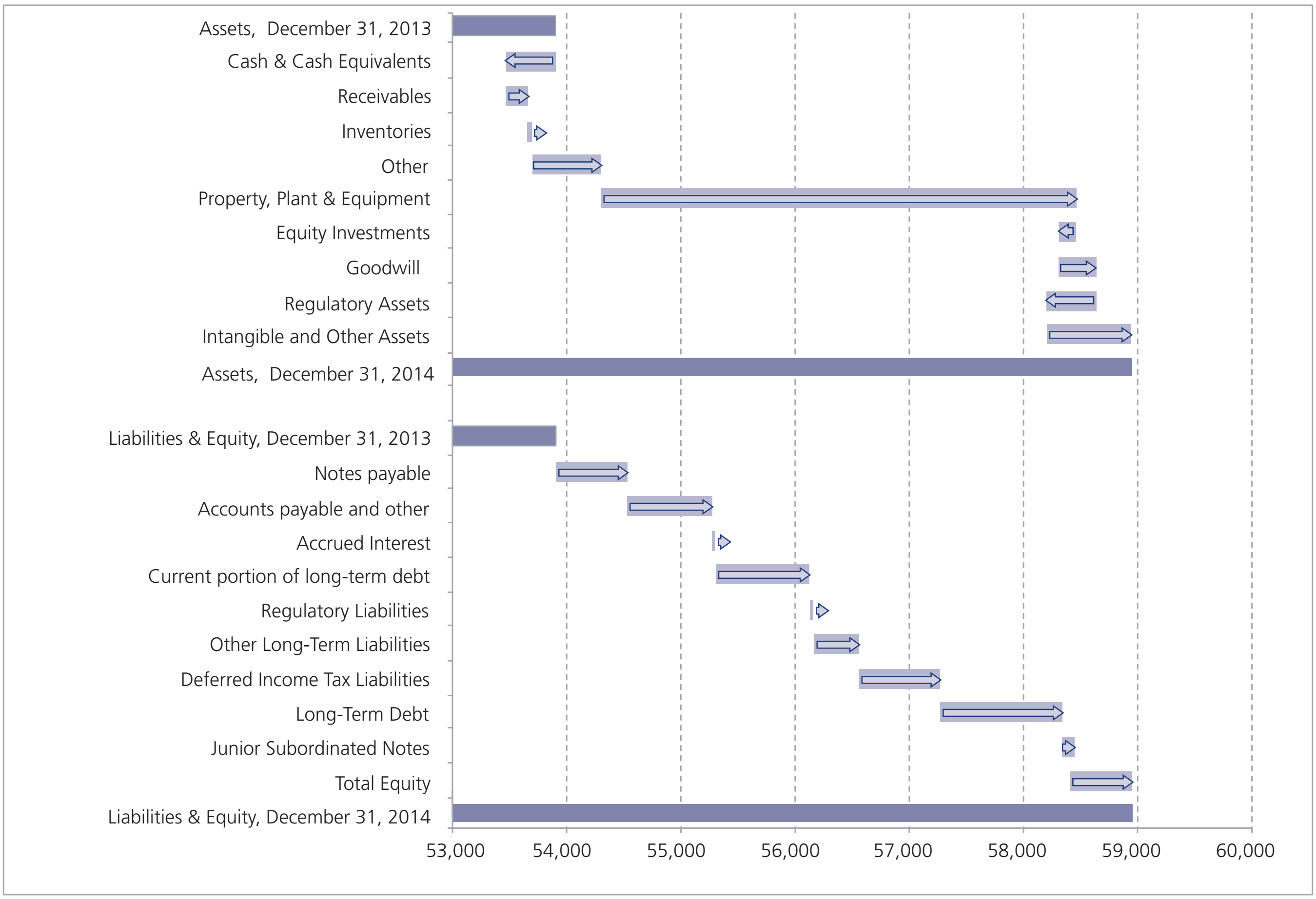
Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets to meet our financing needs, manage our capital structure and to preserve our credit ratings.

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, proceeds from the sale of natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

Balance sheet analysis

As of December 31, 2014, assets increased by $5.0 billion, liabilities increased by $4.5 billion and equity rose by $0.5 billion compared to December 31, 2013.



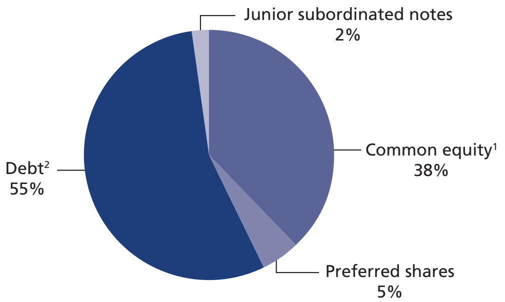
The increase in assets was primarily due to increases in property, plant and equipment and intangible and other assets. Property, plant and equipment increased by $4.2 billion primarily due to the completion of the Gulf Coast Extension of the Keystone Pipeline System, further investment in the NGTL System, investment in our Mexican pipelines projects, construction of the Houston Lateral and Tank Terminal and the expansion of our ANR pipeline. Intangible and other assets rose by $0.7 billion primarily due to spending on our capital projects under development.

The increase in liabilities was primarily due to an increase in long-term debt and notes payable used to fund our growth. In 2014, we issued $1.4 billion and repaid $1.1 billion of long term debt. The strengthening of the U.S. dollar also contributed a $1.6 billion increase on translation of our U.S. dollar-denominated debt. In 2014, notes payable increased by $0.6 billion.

Total equity increased $0.5 billion in 2014 mainly due to a $450 million preferred share issuance in January 2014.

Consolidated capital structure

at December 31, 2014



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

As at December 31, 2014, we had unused capacity of $1.55 billion, $2.0 billion and US$2.75 billion under our equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to the North American debt and equity markets.

As at December 31, 2014, we were in compliance with all of our financial covenants. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can 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.

Cash flows

The following tables summarize the cash flows of our business.

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Net cash provided by operations	**4,079**	3,674	3,571
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)
(Deficiency)/surplus	**(65)**	(1,446)	315
Net cash (used in)/provided by financing activities	**(373)**	1,794	(403)
	(438)	348	(88)
Effect of foreign exchange rate changes on Cash and Cash Equivalents	**-**	28	(15)
Net change in Cash and Cash Equivalents	**(438)**	376	(103)

We continue to fund our extensive capital program through cash flow from operations supplemented by capital market financing activities and the sale of our U.S. natural gas pipeline assets to TC PipeLines, LP.

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., additional drop downs of our U.S. natural gas pipeline assets into TC PipeLines, LP and cash on hand.

Net cash provided by operations

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Funds generated from operations	**4,268**	4,000	3,284
(Increase)/decrease in operating working capital	**(189)**	(326)	287
Net cash provided by operations	**4,079**	3,674	3,571

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 24 for more information about non-GAAP measures. The increase in 2014 compared to 2013 was driven by the increase in comparable earnings adjusted for the following non-cash items: increased deferred income tax expense and depreciation, higher equity AFUDC income and lower equity earnings. Funds generated from operations also reflected lower distributed earnings from equity investments.

At December 31, 2014, our current liabilities were higher than our current assets, leaving us with a working capital deficit of $4.0 billion. This short-term deficiency was mainly due to the use of accounts payable, notes payable and the current portion of our long-term debt to fund our capital program.

This short-term deficiency is considered to be in the normal course of a growing business and is managed through:

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

Net cash used in investing activities

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Capital expenditures	**(3,550)**	(4,264)	(2,595)
Capital projects under development	**(807)**	(488)	(3)
Equity investments	**(256)**	(163)	(652)
Acquisitions, net of cash acquired	**(241)**	(216)	(214)
Proceeds from sale of assets, net of transaction costs	**196**	-	-
Deferred amounts and other	**514**	11	208
Net cash used in investing activities	**(4,144)**	(5,120)	(3,256)

Our 2014 capital spending was incurred primarily for expanding our NGTL System, construction of our Mexican pipelines, construction of the Houston Lateral and Tank Terminal, development of our Energy East Pipeline and expansion of the ANR pipeline. Also included in investing activities in 2014 was the acquisition of an additional four solar facilities in Ontario, proceeds from the sale of Cancarb and its related power generation facilities and our contribution for the construction of Grand Rapids Pipeline.

Net cash (used in)/provided by financing activities

year ended December 31 (millions of $)	**2014**	**2013**	**2012**
Long-term debt issued, net of issue costs	**1,403**	4,253	1,491
Long-term debt repaid	**(1,069)**	(1,286)	(980)
Notes payable issued/(repaid), net	**544**	(492)	449
Dividends and distributions paid	**(1,617)**	(1,522)	(1,416)
Common shares issued	**47**	72	53
Preferred shares issued, net of issue costs	**440**	585	-
Partnership units of subsidiary issued, net of issue costs	**79**	384	-
Preferred shares of subsidiary redeemed	**(200)**	(200)	-
Net cash (used in)/provided by financing activities	**(373)**	1,794	(403)

Long-term debt issued

(millions of $) Company	Issue date	Type	Maturity date	Amount	Interest Rate
TCPL	January 2015	Senior Unsecured Notes	January 2018	US$500	1.88%
	January 2015	Senior Unsecured Notes	January 2018	US$250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US$1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US$625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US$625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US$500	Floating
	July 2013	Medium-Term Notes	July 2023	$450	3.69%
	July 2013	Medium-Term Notes	November 2041	$300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US$750	0.75%
	August 2012	Senior Unsecured Notes	August 2022	US$1,000	2.50%
	March 2012	Senior Unsecured Notes	March 2015	US$500	0.88%
TC PipeLines, LP	July 2013	Unsecured Term Loan Facility	July 2018	US$500	Floating

Long-term debt retired

(millions of $) Company	Retirement date	Type	Amount	Interest Rate
TCPL	January 2015	Senior Unsecured Notes	US$300	4.88%
	June 2014	Debentures	$125	11.10%
	February 2014	Medium-Term Notes	$300	5.05%
	January 2014	Medium-Term Notes	$450	5.65%
	August 2013	Senior Unsecured Notes	US$500	5.05%
	June 2013	Senior Unsecured Notes	US$350	4.00%
	May 2012	Senior Unsecured Notes	US$200	8.63%
Nova Gas Transmission Ltd.	June 2014	Debentures	$53	11.20%
	December 2012	Debentures	US$175	8.50%

Preferred share issuance, redemption and conversion

In January 2014, we completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $450 million. Investors are entitled to receive fixed cumulative dividends at an annual rate of $1.0625 per share, payable quarterly. The dividend rate will reset on October 30, 2019 and every five years thereafter to a yield per annum equal to the sum of the then five-year Government of Canada bond yield and 2.35 per cent. The preferred shares are redeemable by us on or after October 30, 2019 and on October 30 of every fifth year thereafter at a price of $25 per share plus accrued and unpaid dividends. Investors will have the right to convert their shares into Series 10 cumulative redeemable first preferred shares on October 30, 2019 and on October 30 of every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annualized rate equal to the sum of the then 90-day Government of Canada treasury bill rate and 2.35 per cent.

In March 2014, we redeemed all four million 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 they carried an aggregate of $11 million in annualized dividends.

In December 2014, Series 1 shareholders elected to convert 12.5 million of our 22 million outstanding Series 1 cumulative redeemable first preferred shares, on a one-for-one basis into Series 2 floating-rate cumulative redeemable first preferred shares. The Series 1 shares will yield an annual fixed dividend rate of 3.266 per cent, paid on a quarterly basis, for the five-year period which began on December 31, 2014. The Series 2 shares will pay a floating quarterly dividend at an annualized rate equal to the sum of the 90-day Government of Canada treasury bill rate and 1.92 per cent for the five-year period which began on December 31, 2014. The floating quarterly dividend rate for the Series 2 shares for the first quarterly floating rate period, commencing December 31, 2014, is 2.815 per cent per annum and will be reset each quarter going forward.

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

TC PipeLines, LP at-the-market (ATM) equity issuance program

In August 2014, TC PipeLines, LP initiated its at-the-market equity issuance program (ATM program) under which it is authorized to offer and sell common units having an aggregate offering price of up to US$200 million.

From August until December 31, 2014, 1.3 million common units were issued under the ATM program generating net proceeds of approximately US$73 million. Our ownership interest in TC PipeLines, LP will decrease as a result of equity issuances under the ATM program.

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, 2014, we had $6.7 billion (2013 – $6.2 billion) in unsecured credit facilities, including:

Amount	Unused capacity	Subsidiary	For	Matures
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program	December 2019
US$1 billion	US$1 billion	TransCanada PipeLine USA Ltd. (TCPL USA)	Committed, syndicated, revolving extendible, credit facility that is used for TCPL USA general corporate purposes	November 2015
US$1 billion	US$1 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 2015
$1.4 billion	$0.6 billion	TCPL/TCPL USA	Demand lines for issuing letters of credit and as a source of additional liquidity. At December 31, 2014, we had outstanding $0.8 billion in letters of credit under these lines.	Demand

At December 31, 2014, our operated affiliates had $0.4 billion of undrawn capacity on committed credit facilities.

Contractual obligations

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	2,467	2,467	-	-	-
Long-term debt (includes junior subordinated notes)	25,961	1,797	3,071	2,773	18,320
Operating leases (future payments for various premises, services and equipment, less sub-lease receipts)	1,694	300	575	432	387
Purchase obligations	4,221	2,201	1,251	453	316
Other long-term liabilities reflected on the balance sheet	416	8	17	19	372
	34,759	6,773	4,914	3,677	19,395

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 2014, we had $25 billion of long-term debt and $1.2 billion of junior subordinated notes, compared to $22.9 billion of long-term debt and $1.1 billion of junior subordinated notes at December 31, 2013.

Total notes payable were $2.5 billion at the end of 2014 compared to $1.8 billion at the end of 2013.

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

At December 31, 2014, scheduled principal repayments and interest payments related to our long-term debt were as follows:

Principal repayments

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Notes payable	2,467	2,467	-	-	-
Long-term debt	24,801	1,797	3,071	2,773	17,160
Junior subordinated notes	1,160	-	-	-	1,160
	28,428	4,264	3,071	2,773	18,320

Interest payments

Payments due (by period)

at December 31, 2014 (millions of $)	Total	less than 12 months	12 - 36 months	37 - 60 months	more than 60 months
Long-term debt	17,878	1,328	2,467	2,226	11,857
Junior subordinated notes	3,867	74	147	147	3,499
	21,745	1,402	2,614	2,373	15,356

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 five years.

Our commitments under the Alberta PPAs are considered operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Fixed payments under these PPAs have been included in our summary of future obligations. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. Our share of power purchased under the PPAs in 2014 was $391 million (2013 – $242 million; 2012 – $238 million).

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 obligations 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)[1]

at December 31, 2014 (millions of $)	**Total**	**less than 12 months**	**12 - 36 months**	**37 - 60 months**	**more than 60 months**
Natural Gas Pipelines					
Transportation by others[2]	346	94	171	64	17
Capital spending[3]	912	841	71	-	-
Other	6	2	4	-	-
Liquids Pipelines					
Capital spending[3]	1,784	908	651	225	-
Other	70	7	14	14	35
Energy					
Commodity purchases	308	163	125	20	-
Capital spending[3]	205	127	78	-	-
Other[4]	570	48	129	130	263
Corporate					
Information technology and other	20	11	8	-	1
	4,221	2,201	1,251	453	316

1 The amounts in this table exclude funding contributions to our pension plans.
2 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude commodity charges incurred when volumes flow.
3 Amounts include capital expenditures and capital projects under development, are estimates and are subject to variability based on timing of construction and project enhancements.
4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, use of natural gas storage facilities, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

Outlook

We are developing quality projects under our long-term $46 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 cash flow.

Our $46 billion capital program is comprised of $12 billion of small to medium-sized, shorter-term projects and $34 billion of commercially secured large-scale, medium – and longer-term 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
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- portfolio management.

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

GUARANTEES

Bruce Power

We and our partner, BPC, have each severally guaranteed 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 IESO to restart the Bruce A power generation units, and certain other financial obligations. The Bruce A guarantees have terms to 2019.

At December 31, 2014, our share of the potential exposure under the Bruce A and B guarantees was estimated to be $634 million. The carrying amount of these guarantees was estimated to be $6 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 to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2014 to be a maximum of $104 million. The carrying amount of these guarantees was $14 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 2015, we expect to make funding contributions of approximately $70 million for the defined benefit pension plans, approximately $7 million for the other post-retirement benefit plans and approximately $36 million for the savings plan and defined contribution pension plans. In addition, the Company expects to provide a $35 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

In 2014, we made funding contributions of $73 million to our defined benefit pension plans, $6 million for the other post-retirement benefit plans and $37 million for the savings plan and defined contribution pension plans. We also provided a $47 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 2014 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 decreased to $115 million in 2014 from $134 million, mainly due to a higher 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, which includes ensuring that 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

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror, or natural disasters and other catastrophic events.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	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 also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our reputation and relationship with our stakeholders, such as Aboriginal communities, other communities, landowners, governments and government agencies, and environmental non-governmental organizations is very important.	These stakeholders can have a significant impact on our operations, infrastructure development and overall reputation.	Our Stakeholder Engagement Framework 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 and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	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.	Under some contracts, we share the cost of execution risks with customers, in exchange for the potential benefit they will realize when the project is finished.

Risk and Description	Impact	Monitoring and Mitigation
Cyber security		
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.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees.

Pipeline abandonment costs

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

The NEB provided several key guiding principles under this initiative, 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. Pipeline companies are responsible for managing the collection and investment of funds to cover future abandonment costs.

All hearings have been completed and Board decisions have been received, with the final decision in December 2014, providing approval to begin collection through an abandonment surcharge in January 2015. Collection of funds will be held in trusts which will serve to hold and invest funds collected to cover future abandonment costs.

Health, safety and environment

The Health, Safety and Environment committee of TransCanada's Board of Directors (the Board) monitors compliance with our HSE corporate commitment statement through regular reporting from management. We have an integrated HSE Management System that is used to capture, organize and document our related policies, programs and procedures.

The HSE Management System is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and various other internal management systems. It follows a continuous improvement cycle.

The committee reviews HSE performance and operational risk management on a quarterly basis. It receives detailed reports on:

- overall HSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- developments in and compliance with applicable legislation and regulations.

The committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

The safety and integrity of our existing and newly-developed infrastructure is 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. In 2014, we spent $550 million for pipeline integrity on the natural gas and liquids pipelines we operate, an increase of $174 million over 2013 primarily due to increased levels of in-line pipeline inspections and related maintenance projects 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 generally have no impact on our earnings. Our safety record in 2014 continued to meet or exceed industry benchmarks.

Our Energy operations spending associated with process safety and our various integrity programs is used to minimize risk to employees and the public, process equipment, the surrounding environment, and to prevent disruptions to serving the electrical needs of our customers, within the footprint of each facility.

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 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 and new regulations.

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

Environmental compliance and liabilities

Our facilities are subject to 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, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders affecting 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 against us 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, 2014, we had accrued approximately $30 million related to these obligations ($32 million at the end of 2013). 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, 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 $38 million for the Alberta Specified Gas Emitters Regulation in 2014 (2013 – $25 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 2014, we recorded $6 million (2013 – $6 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 $9 million in 2014 (2013 – $6 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 in 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 and 2014. The remaining requirements were purchased through auctions. The cost of these emissions units is recovered through commercial contracts.The pipeline facilities in Québec are also covered under this regulation and have purchased compliance instruments. We recorded approximately $1 million for compliance with this regulation in 2014 (2013 – less than $1 million)
- 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 in 2014 (2013 – 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 energy 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, this exposure increases. The majority 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

2014	**1.10**
2013	1.03
2012	1.00

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 24 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2014**	**2013**	**2012**
U.S. and International Natural Gas Pipelines comparable EBIT	**630**	542	660
U.S. Liquids Pipelines comparable EBIT	**570**	389	363
U.S. Power comparable EBIT	**269**	216	88
Interest on U.S. dollar-denominated long-term debt	**(854)**	(766)	(740)
Capitalized interest on U.S. dollar-denominated capital expenditures	**154**	219	124
U.S. non-controlling interests and other	**(234)**	(196)	(192)
	535	404	303

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:

	2014		**2013**	
at December 31 (millions of $)	**Fair value[1]**	**Notional or principal amount**	**Fair value[1]**	**Notional or principal amount**
U.S. dollar cross-currency interest rate swaps (maturing 2015 to 2019)[2]	**(431)**	**US 2,900**	(201)	US 3,800
U.S. dollar foreign exchange forward contracts (maturing 2015)	**(28)**	**US 1,400**	(11)	US 850
	(459)	**US 4,300**	(212)	US 4,650

1 Fair values equal carrying values.

2 Consolidated net income in 2014 included net realized gains of $21 million (2013 – gains of $29 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 $)	**2014**	**2013**
Carrying value	**17,000 (US 14,700)**	14,200 (US 13,400)
Fair value	**19,000 (US 16,400)**	16,000 (US 15,000)

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 $)	**2014**	**2013**
Other current assets	**5**	5
Intangible and other assets	**1**	-
Accounts payable and other	**(155)**	(50)
Other long-term liabilities	**(310)**	(167)
	(459)	(212)

Counterparty credit risk

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

- accounts receivable

- portfolio investments
- the fair value of derivative assets
- cash and 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 that 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 2014 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $258 million (US$222 million) at December 31, 2014 with one counterparty (2013 – $240 million (US$225 million)). 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 90 Financial condition for more information about our liquidity.

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, 2014 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, 2014 based on the criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2014, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included herein.

Changes in internal control over financial reporting

Effective January 1, 2014, management successfully implemented an Enterprise Resource Planning (ERP) system, and made changes to certain related processes. As a result of the ERP system, certain processes supporting our internal control over financial reporting changed in 2014.

Other than this ERP system implementation there has been no change in our internal control over financial reporting that occurred during the year covered by this annual report that has materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. Although this implementation changed certain specific activities within the accounting function, it did not significantly affect the overall controls and procedures we follow in establishing internal controls over financial reporting.

CEO AND CFO CERTIFICATIONS

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2014 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 from those estimates.

Rate-regulated accounting

Under GAAP, an asset 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 and certain liquids pipelines projects 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 $)	**2014**	**2013**
Regulatory assets		
Long-term assets	**1,297**	1,735
Short-term assets (included in other current assets)	**16**	42
Regulatory liabilities		
Long-term liabilities	**263**	229
Short-term liabilities (included in accounts payable and other)	**30**	7

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 and record 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 first 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 to its book value, including its goodwill. 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 unit 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, North American natural gas production and prices as well as natural gas storage market conditions. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$243 million at December 31, 2014 (2013 – US$246 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.

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 purchase 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.

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 and are designated for hedge accounting treatment. 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.

The majority of 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 derivatives for 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 or refunded 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 has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. 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 derivative instruments is as follows:

at December 31 (millions of $)	**2014**	**2013**
Other current assets	**409**	395
Intangible and other assets	**93**	112
Accounts payable and other	**(749)**	(357)
Other long-term liabilities	**(411)**	(255)
	(658)	(105)

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, 2014 (millions of $)	**Total fair value**	**2015**	**2016 and 2017**	**2018 and 2019**	**2020 and thereafter**
Derivative instruments held for trading					
Assets	436	363	62	7	4
Liabilities	(530)	(457)	(61)	(12)	-
Derivative instruments in hedging relationships					
Assets	66	47	17	2	-
Liabilities	(630)	(293)	(246)	(91)	-
	(658)	(340)	(228)	(94)	4

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 $)	2014	2013
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the year		
Power	**(5)**	19
Natural Gas	**(35)**	17
Foreign Exchange	**(20)**	(10)
Amount of realized (losses)/gains in the year		
Power	**(39)**	(49)
Natural Gas	**11**	(13)
Foreign Exchange	**(28)**	(9)
Derivative instruments in hedging relationships[2,3]		
Amount of realized gains/(losses) in the year		
Power	**130**	(19)
Natural Gas	**-**	(2)
Interest	**4**	5

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, 2014, 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 $3 million (2013 – $5 million) and a notional amount of US$400 million (2013 – US$200 million). In 2014, net realized gains on fair value hedges were $7 million (2013 – $6 million) and were included in interest expense. In 2014 and 2013, 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 2014 and 2013, 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)	2014	2013
Change in fair value of derivative instruments recognized in OCI (effective portion)		
Power	**(126)**	117
Natural Gas	**(2)**	(1)
Foreign Exchange	**10**	5
	(118)	121
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]		
Power	**(114)**	40
Natural Gas	**3**	4
Interest	**16**	16
	(95)	60
(Losses)/gains on derivative instruments recognized in earnings (ineffective portion)		
Power	**(13)**	8
	(13)	8

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.

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, 2014, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $15 million (2013 – $16 million), with collateral provided in the normal course of business of nil (2013 – nil).

If the credit-risk-related contingent features in these agreements were triggered on December 31, 2014, we would have been required to provide additional collateral of $15 million (2013 – $16 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 2014

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 new guidance was effective January 1, 2014 and there was no material impact on our consolidated financial statements as a result of applying this new standard.

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 new guidance was applied prospectively from January 1, 2014.

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 new guidance was effective January 1, 2014 and there was no material impact on our consolidated financial statements as a result of applying this new standard.

Future accounting changes

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance is effective from January 1, 2015 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

Revenue from contracts with customers

In May 2014, the FASB issued new guidance on Revenue from Contracts with Customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. This new guidance is effective from January 1, 2017 with two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. Early application is not permitted. We are currently evaluating the impact of the adoption of this ASU and have not yet determined the effect on our consolidated financial statements.

Reconciliation of Non-GAAP measures

year ended December 31 (millions of $, except per share amounts)	2014	2013	2012
EBITDA	**5,542**	4,958	4,204
Cancarb gain on sale	**(108)**	-	-
Niska contract termination	**43**	-	-
Gas Pacifico/INNERGY gain on sale	**(9)**	-	-
NEB 2013 Decision – 2012	**-**	(55)	-
Sundance A PPA arbitration decision – 2011	**-**	-	20
Non-comparable risk management activities	**53**	(44)	21
Comparable EBITDA	**5,521**	4,859	4,245
Comparable depreciation and amortization	**(1,611)**	(1,472)	(1,375)
Comparable EBIT	**3,910**	3,387	2,870
Other income statement items			
Comparable interest expense	**(1,198)**	(984)	(976)
Comparable interest income and other	**112**	42	86
Comparable income taxes	**(859)**	(662)	(477)
Net income attributable to non-controlling interests	**(153)**	(125)	(118)
Preferred share dividends	**(97)**	(74)	(55)
Comparable earnings	**1,715**	1,584	1,330
Specific items (net of tax)			
Cancarb gain on sale	**99**	-	-
Niska contract termination	**(32)**	-	-
Gas Pacifico/INNERGY gain on sale	**8**	-	-
NEB 2013 Decision – 2012	**-**	84	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	(15)
Risk management activities[1]	**(47)**	19	(16)
Net income attributable to common shares	**1,743**	1,712	1,299
Comparable depreciation and amortization	**(1,611)**	(1,472)	(1,375)
Specific item:			
NEB 2013 Decision – 2012	**-**	(13)	-
Depreciation and amortization	**(1,611)**	(1,485)	(1,375)
Comparable interest expense	**(1,198)**	(984)	(976)
Specific items:			
NEB 2013 Decision – 2012	**-**	(1)	-
Interest expense	**(1,198)**	(985)	(976)
Comparable interest income and other	**112**	42	86
Specific items:			
NEB 2013 Decision – 2012	**-**	1	-
Risk management activities[1]	**(21)**	(9)	(1)
Interest income and other	**91**	34	85
Comparable income tax expense	**(859)**	(662)	(477)
Specific items:			
Cancarb gain on sale	**(9)**	-	-
Niska contract termination	**11**	-	-
Gas Pacifico/INNERGY gain on sale	**(1)**	-	-
NEB 2013 Decision – 2012	**-**	42	-
Part VI.I income tax adjustment	**-**	25	-
Sundance A PPA arbitration decision – 2011	**-**	-	5
Risk management activities[1]	**27**	(16)	6
Income tax expense	**(831)**	(611)	(466)

year ended December 31 ($ per share)	2014	2013	2012
Comparable earnings per common share	**$2.42**	$2.24	$1.89
Specific items (net of tax):			
Cancarb gain on sale	**0.14**	-	-
Niska contract termination	**(0.04)**	-	-
Gas Pacifico/INNERGY gain on sale	**0.01**	-	-
NEB 2013 Decision – 2012	**-**	0.12	-
Part VI.I Income tax adjustment	**-**	0.04	-
Sundance A PPA arbitration decision – 2011	**-**	-	(0.02)
Risk management activities[1]	**(0.07)**	0.02	(0.03)
Net income per common share	**$2.46**	$2.42	$1.84

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year ended December 31 (millions of $)	2014	2013	2012
Canadian Power	**(11)**	(4)	4
U.S. Power	**(55)**	50	(1)
Natural Gas Storage	**13**	(2)	(24)
Foreign exchange	**(21)**	(9)	(1)
Income taxes attributable to risk management activities	**27**	(16)	6
Total (losses)/gains from risk management activities	**(47)**	19	(16)

Comparable EBITDA and comparable EBIT by business segment

year ended December 31, 2014 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**3,250**	**1,059**	**1,360**	**(127)**	**5,542**
Cancarb gain on sale	**-**	**-**	**(108)**	**-**	**(108)**
Niska contract termination	**-**	**-**	**43**	**-**	**43**
Gas Pacifico/INNERGY gain on sale	**(9)**	**-**	**-**	**-**	**(9)**
Non-comparable risk management activities	**-**	**-**	**53**	**-**	**53**
Comparable EBITDA	**3,241**	**1,059**	**1,348**	**(127)**	**5,521**
Comparable depreciation and amortization	**(1,063)**	**(216)**	**(309)**	**(23)**	**(1,611)**
Comparable EBIT	**2,178**	**843**	**1,039**	**(150)**	**3,910**

year ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	2,907	752	1,407	(108)	4,958
NEB 2013 Decision – 2012	(55)	-	-	-	(55)
Non-comparable risk management activities	-	-	(44)	-	(44)
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	Liquids Pipelines	Energy	Corporate	Total
EBITDA	2,741	698	862	(97)	4,204
Sundance A PPA arbitration decision – 2011	-	-	20	-	20
Non-comparable risk management activities	-	-	21	-	21
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

QUARTERLY RESULTS

Selected quarterly consolidated financial data

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

2014	Fourth	Third	Second	First
Revenues	**2,616**	**2,451**	**2,234**	**2,884**
Net income attributable to common shares	**458**	**457**	**416**	**412**
Comparable earnings	**511**	**450**	**332**	**422**
Comparable earnings per share	**$0.72**	**$0.63**	**$0.47**	**$0.60**
Share statistics				
Net income per share – basic and diluted	**$0.65**	**$0.64**	**$0.59**	**$0.58**
Dividends declared per common share	**$0.48**	**$0.48**	**$0.48**	**$0.48**

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

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 Liquids Pipelines, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

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

- weather
- customer demand
- market prices for natural gas and power
- 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 fourth quarter 2014, comparable earnings excluded an $8 million after-tax gain on the sale of Gas Pacifico/INNERGY.

In second quarter 2014, comparable earnings excluded a $99 million after-tax gain on the sale of Cancarb Limited and a $32 million after-tax loss related to the termination of the Niska Gas Storage contract.

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 2013 Decision.

FOURTH QUARTER 2014 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2014	2013
Natural gas pipelines	**621**	498
Liquids pipelines	**230**	160
Energy	**219**	301
Corporate	**(43)**	(35)
Total segmented earnings	**1,027**	924
Interest expense	**(323)**	(240)
Interest income and other	**28**	1
Income before income taxes	**732**	685
Income tax expense	**(206)**	(208)
Net income	**526**	477
Net income attributable to non-controlling interests	**(43)**	(38)
Net income attributable to controlling interests	**483**	439
Preferred share dividends	**(25)**	(19)
Net income attributable to common shares	**458**	420
Net income per common share – basic and diluted	**$0.65**	$0.59

Net income attributable to common shares increased by $38 million for the three months ended December 31, 2014 compared to the same period in 2013. Net income included a gain on the sale of Gas Pacifico/INNERGY of $8 million after tax and unrealized gains and losses from changes in certain risk management activities. Excluding the impact of these items, comparable earnings in the three months ended December 31, 2014 increased over the same period in 2013 as discussed below in Comparable earnings.

The items discussed above were excluded from comparable earnings for the relevant periods. Certain unrealized fair value adjustments relating to certain risk management activities are also excluded from comparable earnings. The remainder of net income is equivalent to comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2014	2013
Net income attributable to common shares	**458**	420
Specific items (net of tax):		
Risk management activities[1]	**61**	(10)
Gas Pacifico/INNERGY gain on sale	**(8)**	-
Comparable earnings	**511**	410
Net income per common share	**$0.65**	$0.59
Specific items (net of tax):		
Risk management activities[1]	**0.08**	(0.01)
Gas Pacifico/INNERGY gain on sale	**(0.01)**	-
Comparable earnings per share	**$0.72**	$0.58

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three months ended December 31 (millions of $)	2014	2013
Canadian Power	**(11)**	(2)
U.S. Power	**(85)**	36
Natural Gas Storage	**9**	(5)
Foreign exchange	**(12)**	(9)
Income tax attributable to risk management activities	**38**	(10)
Total (losses)/gains from risk management activities	**(61)**	10

Comparable EBITDA and comparable EBIT by business segment

three months ended December 31, 2014 (millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Comparable EBITDA	**884**	**288**	**385**	**(36)**	**1,521**
Comparable depreciation and amortization	**(272)**	**(58)**	**(79)**	**(7)**	**(416)**
Comparable EBIT	**612**	**230**	**306**	**(43)**	**1,105**

three months ended December 31, 2013 (millions of $)	Natural Gas Pipelines	Liquids 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

Comparable earnings

Comparable earnings in fourth quarter 2014 increased by $101 million or $0.14 per share compared to the same period in 2013. This was primarily the net effect of:

- incremental earnings from the Gulf Coast extension of the Keystone Pipeline System
- higher earnings from Canadian Mainline due to higher incentive earnings recorded in fourth quarter
- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher earnings from Eastern Power due to higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in December 2013 and the second half of 2014
- higher earnings from U.S. Power due to higher generation, higher sales to wholesale, commercial and industrial customers and the impact of higher realized power and capacity prices
- higher interest expense from debt issuances and lower capitalized interest on projects placed in service.

The stronger U.S. dollar this quarter compared to the same period in 2013 positively impacted the translated results of our U.S. businesses, however, this impact was mostly offset by a corresponding increase in interest expense on U.S. dollar-denominated debt as well as realized losses on foreign exchange hedges used to manage our net exposure through our hedging program.

Highlights by business segment

Natural Gas Pipelines

Natural Gas Pipelines segmented earnings increased by $123 million for the three months ended December 31, 2014 compared to the same period in 2013 and included a $9 million pre-tax gain related to the sale of Gas Pacifico/INNERGY in November 2014. This amount has been excluded in our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT and comparable EBITDA.

Comparable depreciation and amortization decreased by $8 million for the three months ended December 31, 2014 compared to the same period in 2013 as fourth quarter 2013 included the annual impact of the 2013-2014 NGTL Settlement approved by the NEB in November 2013. This settlement increased depreciation for 2013 and 2014. This decrease compared to 2013 was partially offset by depreciation on the Tamazunchale Extension for the period in 2014.

Canadian Pipelines

Net income and comparable earnings for the Canadian Mainline increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher incentive earnings recorded in fourth quarter partially offset by higher carrying charges owed to shippers on the positive TSA balance. Results for both periods reflect an ROE of 11.50 per cent on deemed common equity of 40 per cent.

Net income for the NGTL System decreased by $13 million for the three months ended December 31, 2014 compared to the same period in 2013. The decrease was due to increased OM&A costs at risk under the terms of the 2013-2014 NGTL Settlement approved by the NEB in November 2013, partially offset by a higher average investment base in 2014. Additionally, results for the three months ended December 31, 2013 reflect the annual impact of the 2013-2014 NGTL Settlement, which included an ROE of 10.10 per cent on deemed common equity of 40 per cent and annual fixed amounts for certain OM&A costs.

U.S. and International Pipelines

Comparable EBITDA for the U.S. and international pipelines increased by US$35 million for the three months ended December 31, 2014 compared to the same period in 2013. This was due to:

- higher earnings from the Tamazunchale Extension which was placed in service in 2014
- higher transportation revenues on ANR and Great Lakes.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

Liquids Pipelines

Liquids Pipelines segmented earnings increased by $70 million for the three months ended December 31, 2014 compared to the same period in 2013, and are equivalent to comparable EBIT, which along with comparable EBITDA are discussed below.

Comparable EBITDA for the Keystone Pipeline System increased by $94 million for the three months ended December 31, 2014 compared to the same period in 2013. This increase was primarily due to:

- incremental earnings from the Keystone Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable depreciation and amortization increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the Keystone Gulf Coast extension being placed in service.

Energy

Energy segmented earnings decreased by $82 million for the three months ended December 31, 2014 compared to the same period in 2013.

Energy segmented earnings for the three months ended December 31, 2014 and 2013 included unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

	three months ended December 31	
Risk management activities (millions of $, pre-tax)	**2014**	**2013**
Canadian Power	**(11)**	(2)
U.S. Power	**(85)**	36
Natural Gas Storage	**9**	(5)
Total (losses)/gains from risk management activities	**(87)**	29

The quarterly variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our position for these particular derivatives over a certain period of time however; they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impact of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them part of our underlying operations and exclude them in our calculation of comparable EBIT.

Comparable EBITDA for Energy increased by $39 million for the three months ended December 31, 2014 compared to the same period in 2013 due to the net effect of:

- higher earnings from Eastern Power due to higher contractual earnings at Bécancour and incremental earnings from solar facilities acquired in the second half of 2014
- higher earnings from U.S. Power due to increased generation, higher sales to wholesale, commercial and industrial customers and the impact of higher realized power and capacity prices
- lower earnings from Natural Gas Storage due to weaker realized natural gas storage spreads and lower volumes of third party sales.

A stronger U.S. dollar had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for Eastern Power increased by $20 million for the three months ended December 31, 2014 compared to the same period in 2013 because of higher Bécancour contractual earnings and incremental earnings from solar facilities acquired in December 2013 and in the second half of 2014.

Equity income from Bruce A increased by $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to higher generation levels and lower operating expenses. Fourth quarter 2014 results also include the impact of a deemed generation adjustment related to a prior quarter.

Equity income from Bruce B decreased $30 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower volumes and higher operating costs resulting from higher planned outage days.

Comparable EBITDA for U.S. Power increased US$20 million for the three months ended December 31, 2014 compared to the same period in 2013. The increase was the net effect of:

- higher margins and higher sales volumes to wholesale, commercial and industrial customers
- higher realized capacity prices primarily in New York
- higher generation at our hydro and Ravenswood facility offset by lower realized power prices in New York and New England.

Comparable EBITDA for Natural Gas Storage and Other decreased $15 million for the three months ended December 31, 2014 compared to the same period in 2013 mainly due to lower realized natural gas storage spreads and lower volumes of third party sales.

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
KW-M	Kilowatt month
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
investment base	Includes annual average assets in rate base as well as assets under construction
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
rate base	Our investment in assets used to provide transportation services on our natural gas pipelines
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.)
EPA	Environmental Protection Agency (U.S.)
FERC	Federal Energy Regulatory Commission (U.S.)
IEA	International Energy Agency
IESO	Independent Electricity System Operator
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