MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED SEPTEMBER 30, 2014

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. ("we", "our", "us", "its", "Cenovus", or the "Company") dated October 22, 2014, should be read in conjunction with our September 30, 2014 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2013 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2013 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of October 22, 2014, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-GAAP measure is presented in the Financial Results or Liquidity and Capital Resources sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares trading on the Toronto and New York stock exchanges. On September 30, 2014, we had a market capitalization of approximately $23 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "crude oil") production in the first nine months of 2014 was in excess of 199,200 barrels per day and our average natural gas production was 491 MMcf per day. Our refineries processed an average of 424,000 gross barrels per day of crude oil feedstock into an average of 446,000 gross barrels per day of refined products.

Our Strategy

Our strategy is to create long-term value through the development of our vast oil sands resources, our execution excellence, our ability to innovate and our financial strength. We are focused on building our net asset value and paying a strong and sustainable dividend.

Our integrated approach, which enables us to capture the full value chain from production to high-quality end products like transportation fuels, relies on our entire asset mix:

- Oil sands for growth;
- Conventional crude oil for near-term cash flow and diversification of our revenue stream;
- Natural gas for the fuel we use at our oil sands and refining facilities, and for the cash flow it provides to help fund our capital spending programs; and
- Refining to help reduce the impact of commodity price fluctuations.

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek, Christina Lake, Narrows Lake, Telephone Lake, Grand Rapids and our conventional oil opportunities. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta and we plan to continue assessing our emerging resource base through our annual stratigraphic test well drilling program.

We plan to increase our annual net crude oil production, including our conventional oil operations, to more than 500,000 barrels per day. We anticipate the capital investment necessary to achieve this production level will be primarily internally funded through cash flow generated from our crude oil, natural gas and refining operations, as well as prudent use of our balance sheet capacity. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date.

Oil Sands

Our operations include the following steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta:

	Nine Months Ended September 30, 2014		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	56,070	112,140
Christina Lake	50	67,400	134,800
Narrows Lake	50	-	-
Emerging Projects			
Telephone Lake	100	-	-
Grand Rapids	100	-	-

Foster Creek, Christina Lake and Narrows Lake are operated by Cenovus and jointly owned with ConocoPhillips, an unrelated U.S. public company. They are located in the Athabasca region of northeastern Alberta.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flow. This production provides diversification to our revenue stream and enables further development of our oil sands assets. Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations and provides cash flow to help fund our growth opportunities.

	Nine Months Ended September 30, 2014	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow [(2)]	1,087	399
Capital Investment	601	20
Operating Cash Flow Net of Related Capital Investment	486	379

(1) Includes NGLs.
(2) Non-GAAP measure defined in this MD&A.

We have established crude oil and natural gas producing assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, heavy oil assets at Pelican Lake and developing tight oil assets in Alberta.

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. Where we have working interest production from fee lands, we do not pay a third party royalty, rather we pay mineral tax to the government which is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties which may give rise to royalty income and resulted in Operating Cash Flow of $122 million for the nine months ended September 30, 2014. Approximately 50 percent of our total conventional production comes from our fee lands.

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company.

	Ownership Interest (percent)	2014 Gross Nameplate Capacity (Mbbls/d)
Wood River	50	314
Borger	50	146

Our refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with North American commodity price movements. This segment also includes our marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	Nine Months Ended September 30, 2014
Operating Cash Flow [(1)]	533
Capital Investment	111
Operating Cash Flow Net of Related Capital Investment	**422**

(1) Non-GAAP measure defined in this MD&A.

Technology and Environment

Technology development, research activities and the environment are playing increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technology with the goals of increasing recoveries from our reservoirs, while reducing the amount of water, natural gas and electricity consumed in our operations, potentially reducing costs and minimizing our environmental disturbance. The Cenovus culture fosters the pursuit of new ideas and new approaches. We have a track record of developing innovative solutions that unlock challenging crude oil resources and builds on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Dividend

Our disciplined approach to capital allocation includes continuing to pay a strong and sustainable dividend as part of delivering total shareholder return. In each of the first three quarters of 2014, we paid dividends of $0.2662 per share, a 10 percent increase from 2013.

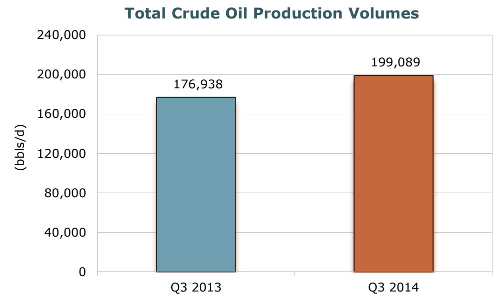
QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

Operating Cash Flow remained relatively consistent in the third quarter compared to 2013. Upstream Operating Cash Flow increased year over year due to significant growth in crude oil production and higher natural gas pricing. This increase was offset by an 11 percent decline in crude oil prices. While the decline in crude oil prices lowered the heavy oil feedstock cost at our refineries, an unplanned outage at our Borger refinery and the start of a planned turnaround at Wood River significantly reduced refined product output decreasing refining Operating Cash Flow.

Operational Results for the Third Quarter of 2014 Compared With the Third Quarter of 2013

Total crude oil production in the third quarter averaged 199,089 barrels per day, up 13 percent from 2013.

Crude oil production from our Oil Sands segment averaged 125,089 barrels per day, an increase of 23 percent, primarily driven by a 30 percent increase in production at Christina Lake. Average production at Christina Lake increased to 68,458 barrels per day due to phase E reaching nameplate production capacity in the second quarter of 2014 and the total facility operating at approximately 99 percent of capacity.



Foster Creek production averaged 56,631 barrels per day, up 15 percent due to an increase in the number of wedge wells coming on stream and the smaller scale third quarter 2014 planned turnaround, which had less of an impact to production as compared to the third quarter 2013 planned major turnaround. In addition, performance also improved as we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring.

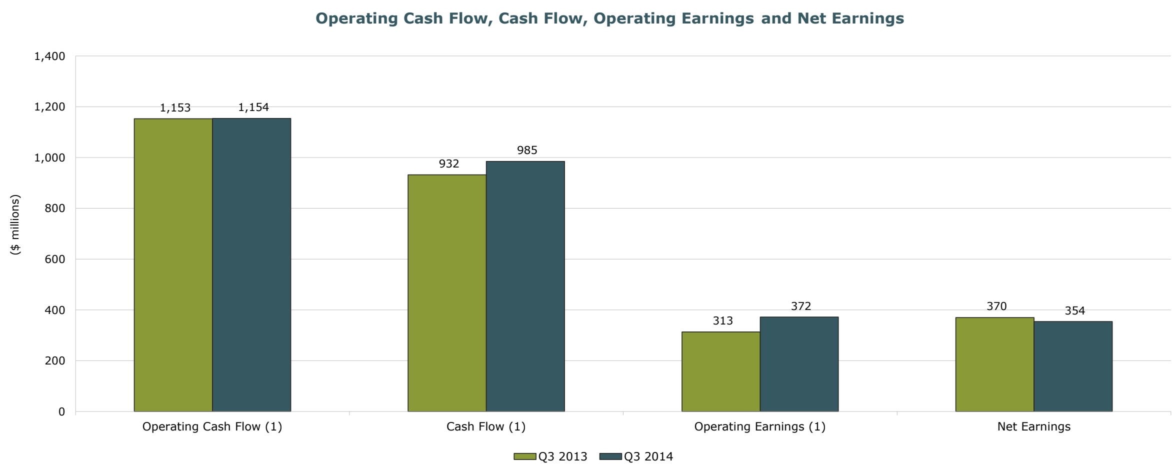
Our Conventional crude oil production averaged 74,000 barrels per day, a slight decrease from 2013. An increase in production from successful horizontal well performance in southern Alberta was offset by a slight decline in production at Pelican Lake, expected natural declines and the sale of our Bakken assets in April 2014. Pelican Lake production declined slightly as a result of a planned turnaround, partially offset by additional infill wells coming on stream and an increased response from the polymer flood program.

As a result of an unplanned coker outage at our Borger refinery and a planned turnaround at Wood River, which commenced in late September 2014, crude oil processed and refined product output declined. We processed an average of 407,000 gross barrels per day (2013 – 464,000 gross barrels per day) of crude oil, of which 201,000 gross barrels per day (2013 – 240,000 gross barrels per day) was heavy crude oil. We produced 429,000 gross barrels per day of refined products, a decrease of 58,000 gross barrels per day, or 12 percent.

Other significant operational results in the third quarter of 2014 include:

- Achieving first production at Foster Creek phase F in September, our eleventh oil sands expansion phase;
- The closing of the sale of certain Wainwright assets for net proceeds of approximately $234 million; and
- Transporting approximately 12,700 barrels per day of crude oil by rail, including 18 unit train shipments.

Financial Results for the Third Quarter of 2014 Compared With the Third Quarter of 2013



(1) Non-GAAP measure defined in this MD&A.

Financial highlights for the third quarter of 2014 compared with 2013 include:

Revenues

Revenues of $4,970 million, a decrease of $105 million or two percent, as a result of:

- Refining and Marketing revenues declining $315 million primarily due to lower refined product output and a decrease in refined product prices, consistent with the decline in Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices, partially offset by the weakening of the Canadian dollar; and
- Lower sales prices for blended crude oil, consistent with the decline in the Western Canada Select ("WCS") benchmark price.

The decreases in revenues were partially offset by an increase in blended crude oil sales volumes and higher sales prices for natural gas.

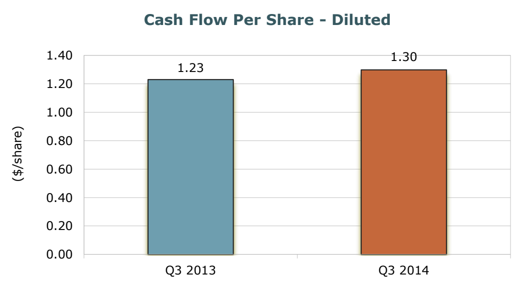
Operating Cash Flow

Operating Cash Flow of $1,154 million was relatively consistent with 2013. Upstream Operating Cash Flow increased seven percent due to higher crude oil sales volumes and an increase in natural gas sales prices, partially offset by lower crude oil sales prices.

The increase in upstream Operating Cash Flow was partially offset by lower Operating Cash Flow from our Refining and Marketing segment, which decreased 51 percent. The decrease was primarily due to a decline in refined product output as a result of an unplanned coker outage and a planned turnaround, partially offset by lower crude oil feedstock costs and higher average market crack spreads.

Cash Flow

Cash Flow increased $53 million to $985 million. While Operating Cash Flow was relatively consistent, as noted above, Cash Flow increased primarily due to lower finance costs. Finance costs declined due to a premium paid on the early redemption of senior unsecured notes in the third quarter of 2013 and lower interest as a result of the prepayment of the Partnership Contribution Payable in the first quarter of 2014.



Operating Earnings

Operating Earnings increased $59 million, or 19 percent, to $372 million. The increase was primarily due to higher Cash Flow discussed above and lower income tax expense related to operating earnings, partially offset by an increase in depreciation, depletion and amortization ("DD&A").

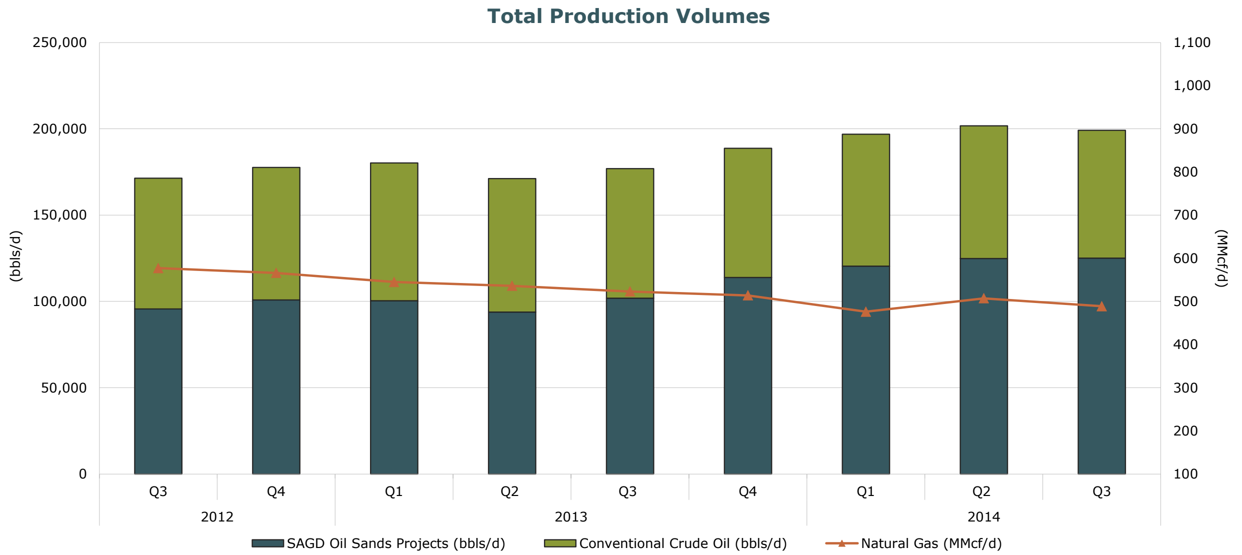
Net Earnings

Net Earnings of $354 million was relatively consistent as the change in unrealized risk management gains and the gain on the sale of certain of our Wainwright assets mostly offset the change in non-operating unrealized foreign exchange losses on our U.S. dollar denominated debt due to the weakening of the Canadian dollar.

Capital Investment

Capital investment was $750 million, with most of our spend occurring on our oil sands assets. We continue to focus on the development of our expansion phases at Foster Creek and Christina Lake, and construction at Narrows Lake.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended September 30, 2014	Percent Change	2013	Nine Months Ended September 30, 2014	Percent Change	2013
Oil Sands						
Foster Creek	**56,631**	**15%**	49,092	**56,070**	**5%**	53,450
Christina Lake	**68,458**	**30%**	52,732	**67,400**	**49%**	45,211
	125,089	**23%**	101,824	**123,470**	**25%**	98,661
Conventional						
Pelican Lake	**24,196**	**(3)%**	24,826	**24,593**	**2%**	24,162
Other Heavy Oil	**14,900**	**(4)%**	15,507	**15,467**	**(4)%**	16,163
Total Heavy Oil	**39,096**	**(3)%**	40,333	**40,060**	**(1)%**	40,325
Light & Medium Oil	**33,548**	**-%**	33,651	**34,488**	**(4)%**	36,081
NGLs (1)	**1,356**	**20%**	1,130	**1,200**	**18%**	1,018
	74,000	**(1)%**	75,114	**75,748**	**(2)%**	77,424
Total Crude Oil Production	**199,089**	**13%**	176,938	**199,218**	**13%**	176,085

(1) NGLs include condensate volumes.

Production from Christina Lake has increased significantly in 2014 due to phase E reaching nameplate production capacity in the second quarter of 2014 and improved performance of our facilities. Our 2014 planned turnaround at phases A and B was successfully completed in the second quarter with minimal impact to production as volumes from phases A and B were processed through the phase C, D and E plant.

Foster Creek production increased from 2013 as a result of more wedge wells coming on stream and a smaller scale planned turnaround, which began late in the third quarter of 2014 and had less of an impact to production as compared to the 2013 planned major turnaround. In addition, performance also improved as we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. In September, we achieved first production from phase F, with ramp up expected to take approximately eighteen months.

At Foster Creek, we continue to be on track with our plan to optimize steam placement and are closely monitoring conditions in the reservoir to track steam movement between well pads. We are also working to improve how steam moves along individual wells through the use of new operating techniques.

Our Conventional crude oil production decreased in 2014. Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines and the divestiture of our Lower Shaunavon and Bakken assets in July 2013 and April 2014, respectively. Pelican Lake production decreased slightly in the third quarter due to a planned turnaround. On a year-to-date basis, Pelican Lake production was higher due to an increased response from the polymer flood program and additional infill wells coming on stream.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Conventional	**466**	500	**469**	514
Oil Sands	**23**	23	**22**	21
	489	523	**491**	535

In 2014, our natural gas production declined as expected. We continue to focus natural gas capital investment on high rate of return projects and direct the majority of our total capital investment to our crude oil properties.

Operating Netbacks

	Three Months Ended September 30,				Nine Months Ended September 30,			
	Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2014	2013	**2014**	2013	**2014**	2013	**2014**	2013
Price [2]	**76.57**	86.28	**4.22**	2.83	**77.04**	69.91	**4.52**	3.20
Royalties	**6.52**	7.40	**0.08**	0.05	**6.56**	5.28	**0.08**	0.05
Transportation and Blending [2]	**3.08**	3.61	**0.11**	0.10	**2.96**	3.00	**0.11**	0.11
Operating Expenses	**14.60**	15.29	**1.24**	1.13	**16.41**	15.88	**1.24**	1.14
Production and Mineral Taxes	**0.54**	0.59	**0.05**	0.03	**0.52**	0.58	**0.06**	0.02
Netback Excluding Realized Risk Management	**51.83**	59.39	**2.74**	1.52	**50.59**	45.17	**3.03**	1.88
Realized Risk Management Gain (Loss)	**(0.45)**	(2.02)	**0.11**	0.38	**(1.78)**	0.45	**0.03**	0.31
Netback Including Realized Risk Management	**51.38**	57.37	**2.85**	1.90	**48.81**	45.62	**3.06**	2.19

(1) Includes NGLs.

(2) The crude oil price and transportation and blending cost excludes the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the third quarter was $28.48 per barrel (2013 – $25.16 per barrel) and in the nine months ended September 30, 2014 was $31.92 per barrel (2013 – $28.05 per barrel).

In the third quarter of 2014, our average crude oil netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices, consistent with the weakening of the West Texas Intermediate ("WTI"), WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by the weakening of the Canadian dollar.

On a year-to-date basis, our average crude oil netback, excluding realized risk management gains and losses, increased primarily due to higher sales prices, consistent with the strengthening of associated benchmark prices and the weakening of the Canadian dollar.

In 2014, our average natural gas netback, excluding realized risk management gains and losses, increased primarily due to higher sales prices, partially offset by higher per-unit operating costs as a result of the decline in production volumes.

Refining [1]

	Three Months Ended September 30, 2014	Percent Change	2013	Nine Months Ended September 30, 2014	Percent Change	2013
Crude Oil Runs (Mbbls/d)	**407**	**(12)%**	464	**424**	**(4)%**	440
Heavy Oil	**201**	**(16)%**	240	**205**	**(8)%**	223
Refined Products (Mbbls/d)	**429**	**(12)%**	487	**446**	**(3)%**	461
Crude Utilization (percent)	**88**	**(13)%**	101	**92**	**(4)%**	96

(1) Represents 100 percent of the Wood River and Borger refinery operations.

In the quarter, an unplanned coker outage at our Borger refinery and the start of a planned turnaround at Wood River reduced crude oil runs and refined product output as compared to 2013. The unplanned outage lasted approximately two weeks. The Wood River planned turnaround will be completed early in the fourth quarter of 2014. On a year-to-date basis, refined product output declined as a result of the third quarter 2014 outages. In 2013, an unplanned hydrocracker outage at Wood River in the second quarter negatively impacted volumes, however not to the same extent.

The decrease in heavy oil processed reflected the optimization of our total crude input slate at each refinery.

Further information on the changes in our production volumes, items included in our operating netbacks and refining statistics can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management section of this MD&A and in the notes to the interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, price differentials, refining crack spreads as well as the U.S./Canadian dollar exchange rate. The following table shows selected market benchmark prices and the U.S./Canadian dollar average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [1]

	Nine Months Ended September 30,				
	2014	2013	**Q3 2014**	Q2 2014	Q3 2013
Crude Oil Prices (US$/bbl)					
Brent					
Average	**107.02**	108.57	**103.39**	109.77	109.71
End of Period	**94.67**	108.37	**94.67**	112.36	108.37
WTI					
Average	**99.61**	98.14	**97.17**	102.99	105.82
End of Period	**91.16**	102.33	**91.16**	105.37	102.33
Average Differential Brent-WTI	**7.41**	10.43	**6.22**	6.78	3.89
WCS [2]					
Average	**78.49**	75.28	**76.99**	82.95	88.34
End of Period	**75.84**	70.39	**75.84**	83.18	70.39
Average Differential WTI-WCS	**21.12**	22.86	**20.18**	20.04	17.48
Condensate (C5 @ Edmonton) Average	**100.41**	104.18	**93.45**	105.15	103.80
Average Differential WTI-Condensate (Premium)/Discount	**(0.80)**	(6.04)	**3.72**	(2.16)	2.02
Average Differential WCS-Condensate (Premium)/Discount	**(21.92)**	(28.90)	**(16.46)**	(22.20)	(15.46)
Average Refined Product Prices (US$/bbl)					
Chicago Regular Unleaded Gasoline ("RUL")	**116.11**	120.62	**113.30**	121.98	119.58
Chicago Ultra-low Sulphur Diesel ("ULSD")	**122.91**	127.75	**118.56**	124.34	126.81
Refining 3-2-1 WTI Average Crack Spreads (US$/bbl)					
Chicago	**18.61**	24.93	**17.57**	19.72	16.19
Group 3	**17.27**	24.17	**16.65**	17.75	17.35
Natural Gas Average Prices					
AECO ($/Mcf)	**4.55**	3.17	**4.22**	4.67	2.82
NYMEX (US$/Mcf)	**4.56**	3.67	**4.06**	4.67	3.58
Basis Differential NYMEX-AECO (US$/Mcf)	**0.39**	0.57	**0.16**	0.40	0.89
Foreign Exchange Rate (US$ per C$1)					
Average	**0.914**	0.977	**0.918**	0.917	0.963

(1) *These benchmark prices do not reflect our realized sales prices. For our average realized sales prices and realized risk management results, refer to the operating netbacks table in the Operating Results section of this MD&A.*

(2) *The Canadian dollar average WCS benchmark price for the third quarter of 2014 was $83.87 per barrel (2013 – $91.73 per barrel) and for the nine months ended September 30, 2014 was $85.88 per barrel (2013 – $77.05 per barrel).*

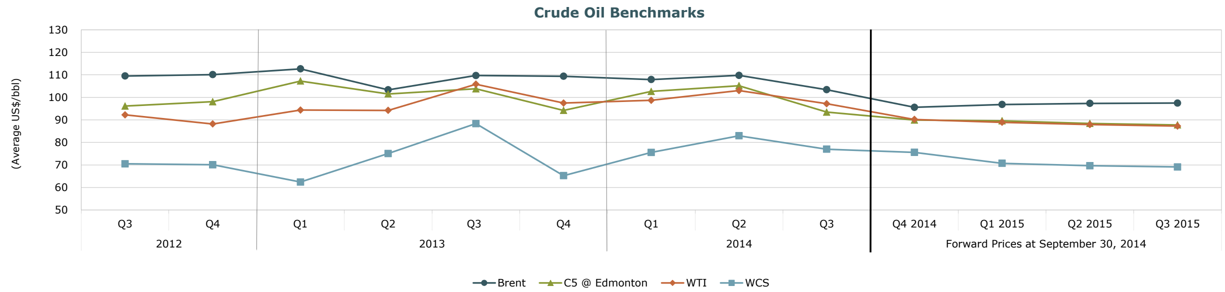
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. The average price of Brent crude oil for the three months ended September 30, 2014 declined by US$6.32 per barrel compared to 2013 due to declining economic conditions in Europe and China which reduced crude oil demand, the sporadic return of Libyan crude oil supply, and consistent growth in North American crude oil supply. On a year-to-date basis, the average price of Brent crude oil decreased with the exception of the second quarter where prices were higher due to unrest in Iraq. Year over year changes highlight the impact of economic weakness in Europe and China.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average discount between WTI and Brent widened by US$2.33 per barrel for the three months ended September 30, 2014 due to growing U.S. domestic crude oil supplies creating light crude oil congestion in both the U.S. midcontinent and U.S. Gulf Coast regions. On a year-to-date basis, the average discount narrowed by US$3.02 per barrel as new pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved severe congestion that developed in the first half of 2013.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential widened by US$2.70 per barrel in the third quarter compared to last year due to growing crude oil supply in Alberta and higher utilization of pipelines. On a year-to-date basis, the differential narrowed by US$1.74 per barrel. This was primarily due to increased Canadian heavy crude oil volumes shipped by rail providing access to more North American markets and improved pipeline performance increasing access to U.S. refineries. In addition, heavy crude oil demand has increased as new coker capacity in the Chicago area came online earlier this year and continues to ramp up.

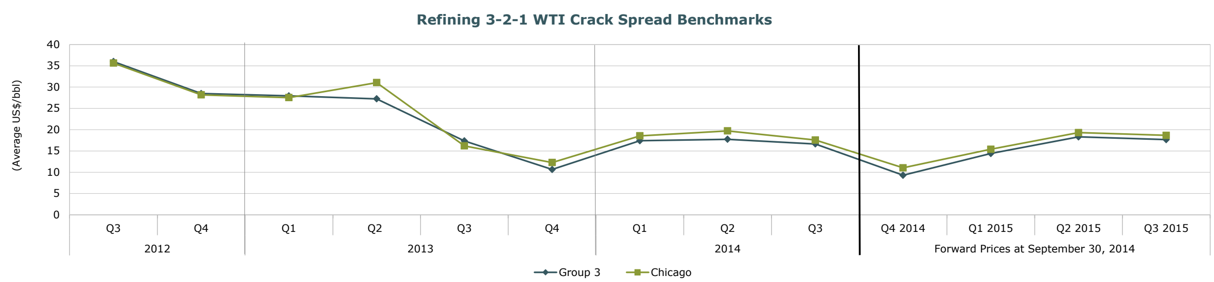
Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Compared to 2013, Edmonton-based condensate prices decreased by US$10.35 per barrel in the quarter due to falling global crude oil prices as well as a narrowing price differential between U.S. Gulf Coast and Edmonton prices resulting from increased import pipeline capacity. On a year-to-date basis, condensate prices decreased by US$3.77 per barrel as a result of additional pipeline capacity from the U.S. Gulf Coast to Western Canada increasing the supply of condensate. The WCS-Condensate differential widened in the third quarter of 2014 compared to 2013 primarily due to the growing crude oil supply in Alberta. On a year-to-date basis, the WCS-Condensate differential narrowed primarily as a result of increased condensate supply in Alberta.



Refining Benchmarks

The Chicago RUL and Chicago ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 Crack Spread. The 3-2-1 WTI crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis. Average inland refined product prices decreased in 2014 as a result of weak Brent prices and high refinery utilization rates increasing product supply. Average market crack spreads for the quarter were largely unchanged from the previous year. On a year-to-date basis, the U.S. inland Chicago and Group 3 markets fell compared with 2013 primarily due to the strengthening of WTI prices relative to global crude oil prices and a reduction in refinery outages in 2014.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, and feedstock costs which are valued on a first in, first out accounting basis.



Other Benchmarks

Average natural gas prices increased in 2014 compared to the prior year due to an abnormally cold winter leading to large draws of natural gas from storage and the subsequent need for larger than normal injections of natural gas into storage.

A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on all of our revenues as the sales prices of our crude oil and natural gas are determined directly in US$ or by reference to US$ benchmarks. In addition, our refining results are in U.S. dollars and therefore a weakened Canadian dollar improves our reported results, although a weaker Canadian dollar also increases our current period's reported refining capital investment and results in unrealized foreign exchange losses on our U.S. dollar denominated debt. In the three and nine months ended September 30, 2014, the Canadian dollar weakened relative to the U.S. dollar by $0.05 or five percent, and $0.06 or six percent, respectively. The Canadian dollar weakened due to narrowing of U.S./Canadian interest differentials as a result of a shift in the Bank of Canada's concern from inflation to deflation risks. The weakening of the Canadian dollar in 2014 as compared with 2013 increased our year-to-date revenues by US$970 million.

FINANCIAL RESULTS

Selected Consolidated Financial Results

For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2013 annual MD&A and 2014 quarterly MD&As. The following key performance indicators are discussed in more detail within this section.

($ millions, except per share amounts)	Nine Months Ended September 30, 2014	2013	2014 Q3	Q2	Q1	2013 Q4	Q3	Q2	Q1	2012 Q4	Q3
Revenues	**15,404**	13,910	**4,970**	5,422	5,012	4,747	5,075	4,516	4,319	3,724	4,340
Operating Cash Flow (1) (2)	**3,619**	3,492	**1,154**	1,296	1,169	976	1,153	1,125	1,214	966	1,314
Cash Flow (1)	**3,078**	2,774	**985**	1,189	904	835	932	871	971	697	1,117
Per Share – Diluted	**4.06**	3.66	**1.30**	1.57	1.19	1.10	1.23	1.15	1.28	0.92	1.47
Operating Earnings (Loss) (1)	**1,223**	959	**372**	473	378	212	313	255	391	(188)	432
Per Share – Diluted	**1.61**	1.27	**0.49**	0.62	0.50	0.28	0.41	0.34	0.52	(0.25)	0.57
Net Earnings (Loss)	**1,216**	720	**354**	615	247	(58)	370	179	171	(117)	289
Per Share – Basic	**1.61**	0.95	**0.47**	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)	0.38
Per Share – Diluted	**1.60**	0.95	**0.47**	0.81	0.33	(0.08)	0.49	0.24	0.23	(0.15)	0.38
Capital Investment (3)	**2,265**	2,364	**750**	686	829	898	743	706	915	978	830
Cash Dividends	**604**	549	**201**	201	202	183	182	183	184	167	166
Per Share	**0.7986**	0.726	**0.2662**	0.2662	0.2662	0.242	0.242	0.242	0.242	0.22	0.22

(1) Non-GAAP measure defined in this MD&A.
(2) Research activities included in operating expense in prior periods were reclassified to conform to the presentation adopted for the year ended December 31, 2013. This increased Operating Cash Flow in prior periods.
(3) Includes expenditures on property, plant and equipment ("PP&E") and exploration and evaluation ("E&E") assets.

Revenues

In the third quarter, revenues decreased $105 million or two percent compared with 2013. On a year-to-date basis, revenues increased $1,494 million or 11 percent compared with 2013.

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2013	**5,075**	**13,910**
Increase (Decrease) due to:		
Oil Sands	**221**	**1,048**
Conventional	**(4)**	**258**
Refining and Marketing	**(315)**	**402**
Corporate and Eliminations	**(7)**	**(214)**
Revenues for the Periods Ended September 30, 2014	**4,970**	**15,404**

Upstream revenues, which include the Oil Sands and Conventional segments, rose in the quarter and year to date by 12 percent and 27 percent, respectively. In the third quarter, the increases were primarily due to higher blended crude oil sales volumes and rising sales prices for natural gas, partially offset by a decline in sales prices for blended crude oil. On a year-to-date basis, higher revenues resulted from an increase in blended crude oil sales volumes and rising sales prices for blended crude oil and natural gas, partially offset by increased royalties.

Revenues for the three months ended September 30, 2014 generated by our Refining and Marketing segment decreased nine percent. The decline was due to lower refined product output as a result of an unplanned coker outage and a planned turnaround, and a decrease in refined product pricing consistent with the decline in the Chicago RUL and Chicago ULSD benchmark prices, partially offset by the weakening of the Canadian dollar. On a year-to-date basis, revenues increased four percent, as revenues from third party sales undertaken by the marketing group increased primarily due to higher blended crude oil and natural gas sales prices and an increase in purchased crude oil volumes. This was partially offset by a decline in revenue from our refining operations which decreased due to lower refined product prices and a decline in refined product output.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

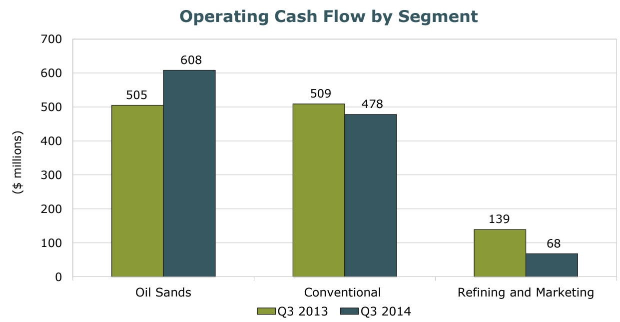
Operating Cash Flow

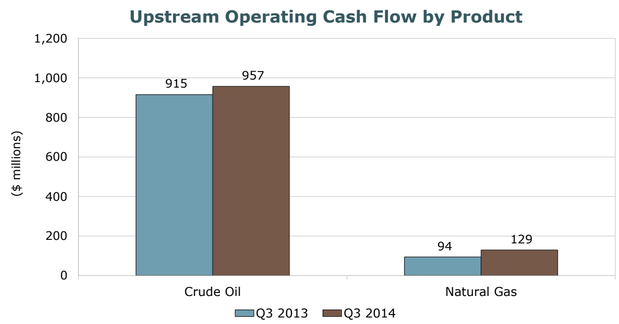
Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating expenses and production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Cash Flow.

Operating Cash Flow

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Revenues	**5,167**	5,265	**16,060**	14,352
(Add) Deduct:				
Purchased Product	**2,918**	3,172	**8,836**	8,065
Transportation and Blending	**592**	464	**1,900**	1,482
Operating Expenses	**491**	432	**1,584**	1,328
Production and Mineral Taxes	**12**	11	**36**	30
Realized (Gain) Loss on Risk Management Activities	**-**	33	**85**	(45)
Operating Cash Flow	**1,154**	1,153	**3,619**	3,492

Three Months Ended September 30, 2014 Compared With September 30, 2013





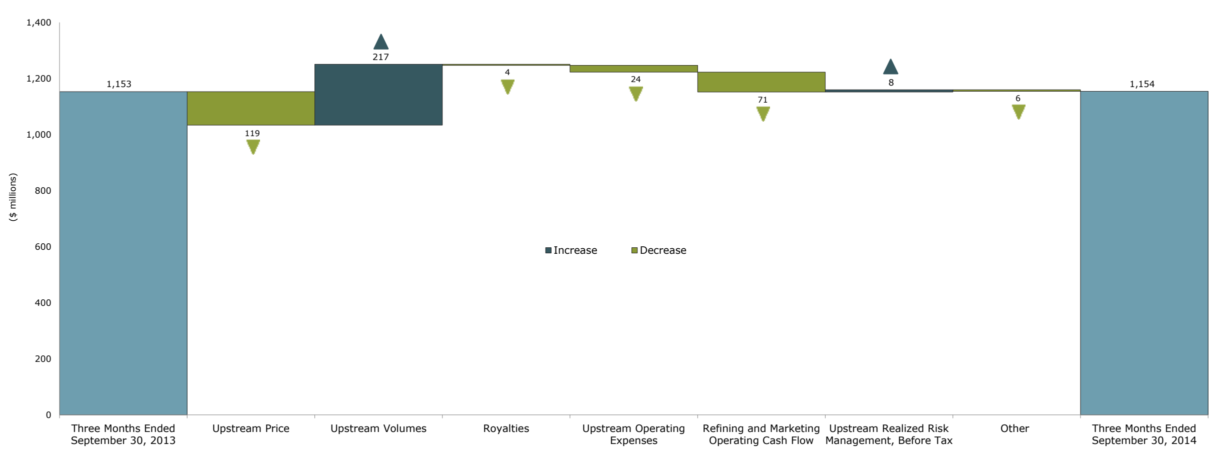
As highlighted in the graph below, our Operating Cash Flow remained relatively consistent in the third quarter compared to 2013 primarily due to:

- An increase in our crude oil sales volumes by 16 percent; and
- A 49 percent increase in our average natural gas sales price to $4.22 per Mcf, consistent with the change in the AECO benchmark price.

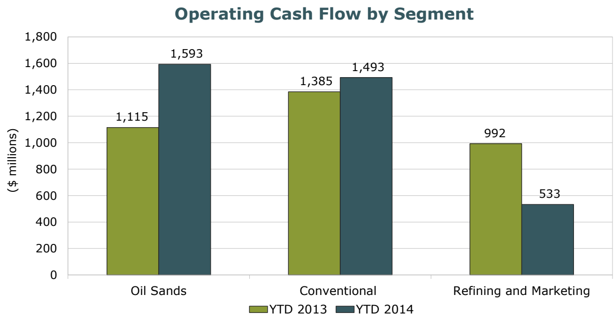
The increases were partially offset by:

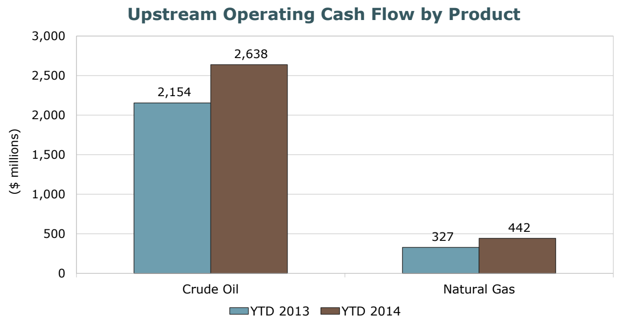
- An 11 percent decrease in our average crude oil sales price to $76.57 per barrel, consistent with the change in associated benchmark prices; and
- A decline of $71 million in Operating Cash Flow from Refining and Marketing primarily due to a decrease in refined product output, partially offset by lower heavy crude oil feedstock costs, consistent with the 13 percent decline in the WCS benchmark price, and higher Chicago 3-2-1 market crack spread.

Operating Cash Flow Variance



Nine Months Ended September 30, 2014 Compared With September 30, 2013





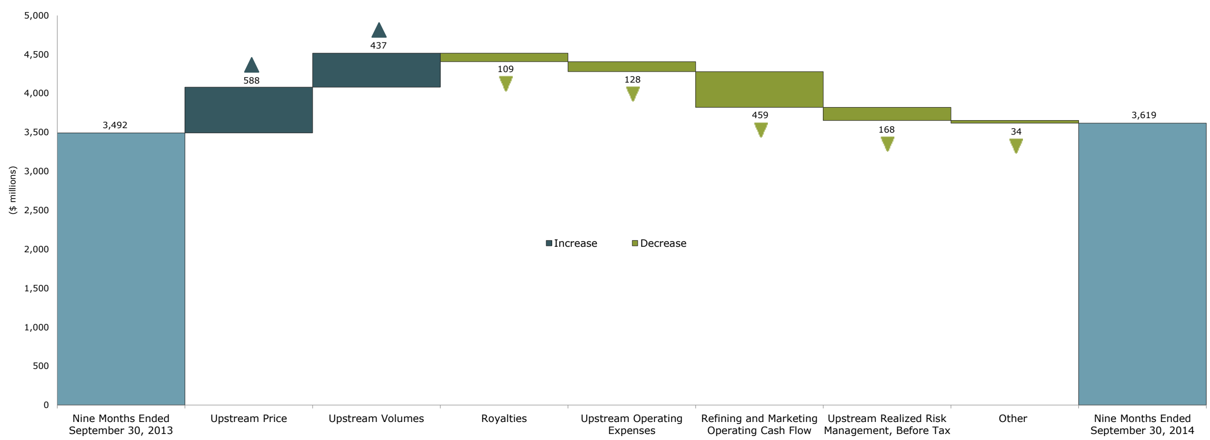
Our Operating Cash Flow increased four percent in the first nine months of 2014 primarily due to:

- A 10 percent increase in our average crude oil sales price to $77.04 per barrel and a 41 percent increase in our average natural gas sales price to $4.52 per Mcf, consistent with the change in associated benchmark prices; and
- An increase in our crude oil sales volumes by 14 percent in line with our increase in production.

The increases were partially offset by:

- A decline of $459 million in Operating Cash Flow from Refining and Marketing primarily due to lower market crack spreads, higher heavy crude oil feedstock costs and lower refined product output;
- Realized risk management losses before tax, excluding Refining and Marketing, of $94 million compared with gains of $74 million in 2013;
- An increase in crude oil operating expenses of $130 million, primarily due to a rise in fuel costs consistent with the increase in the AECO natural gas price and a rise in consumption, consistent with the increase in our production volumes. The impact of rising natural gas prices on our operating expenses was offset by the increase in natural gas revenues, as we produced more natural gas than we used; and
- Higher royalties expense, primarily due to the increase in crude oil sales prices and volumes.

Operating Cash Flow Variance



Additional details explaining the changes in Operating Cash Flow can be found in the Reportable Segments section of this MD&A.

Cash Flow

Cash Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Cash Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Cash From Operating Activities	**1,092**	840	**2,658**	2,563
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(28)**	(25)	**(97)**	(90)
Net Change in Non-Cash Working Capital	**135**	(67)	**(323)**	(121)
Cash Flow	**985**	932	**3,078**	2,774

In the three and nine months ended September 30, 2014, Cash Flow increased $53 million and $304 million, respectively, primarily due to:

- Higher Operating Cash Flow, as discussed above; and
- Lower finance costs as a result of the premium paid on the early redemption of senior unsecured notes in the third quarter of 2013 and the prepayment of the Partnership Contribution Payable in the first quarter of 2014.

In addition, on a year-to-date basis, the increase was also due to:

- A decrease in current income tax, primarily due to a favourable adjustment related to prior years, a decrease in U.S. cash flow, partially offset by an increase in Canadian cash flow; and
- A pre-exploration expense of $63 million recorded in the second quarter of 2013.

Operating Earnings

Operating Earnings is a non-GAAP measure that is used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings is defined as Earnings Before Income Tax excluding gain (loss) on discontinuance, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Earnings, Before Income Tax	**533**	542	**1,715**	1,116
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**(165)**	(8)	**(180)**	196
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**253**	(53)	**272**	91
(Gain) Loss on Divestiture of Assets	**(137)**	1	**(157)**	1
Operating Earnings, Before Income Tax	**484**	482	**1,650**	1,404
Income Tax Expense	**112**	169	**427**	445
Operating Earnings	**372**	313	**1,223**	959

(1) Includes the reversal of unrealized (gains) losses recognized in prior periods.
(2) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and the Partnership Contribution Receivable and foreign exchange (gains) losses on settlement of intercompany transactions.

Operating Earnings increased $59 million in the third quarter and $264 million on a year-to-date basis, primarily due to higher Cash Flow as discussed above.

In addition to higher Cash Flow in the third quarter, deferred income tax expense declined as a result of a decrease in U.S. cash flow, partially offset by an increase in DD&A.

On a year-to-date basis, higher Cash Flow and a decrease in exploration expense was partially offset by an increase in deferred income tax due to higher Canadian income partially offset by a decrease in U.S. cash flow, and higher DD&A.

Net Earnings

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2013	**370**	**720**
Increase (Decrease) due to:		
Operating Cash Flow [(1)]	**1**	**127**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**157**	**376**
Unrealized Foreign Exchange Gain (Loss)	**(307)**	**(135)**
Gain (Loss) on Divestiture of Assets	**138**	**158**
Expenses [(2)]	**47**	**15**
Depreciation, Depletion and Amortization	**(45)**	**(50)**
Exploration Expense	**-**	**108**
Income Tax Expense	**(7)**	**(103)**
Net Earnings for the Periods Ended September 30, 2014	**354**	**1,216**

(1) Non-GAAP measure defined in this MD&A.
(2) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations operating expenses.

Net Earnings for the three months ended September 30, 2014 was relatively unchanged. Unrealized risk management gains of $165 million (Q3 2013 – unrealized risk management gains of $8 million) and the gain of $137 million on the sale of certain of our Wainwright assets mostly offset non-operating unrealized foreign exchange losses of $253 million (Q3 2013 – non-operating unrealized foreign exchange gains of $53 million).

On a year-to-date basis, Net Earnings increased by $496 million, primarily due to an increase in Cash Flow and Operating Earnings as discussed above, in addition to:

- Unrealized risk management gains of $180 million on a year-to-date basis (2013 – unrealized losses of $196 million); and
- A gain on the sale of certain non-core assets of $157 million.

The increases were partially offset by non-operating unrealized foreign exchange losses of $272 million (2013 – unrealized foreign exchange unrealized losses $91 million).

Net Capital Investment

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Oil Sands	**494**	426	**1,492**	1,383
Conventional	**198**	275	**621**	858
Refining and Marketing	**42**	19	**111**	70
Corporate	**16**	23	**41**	53
Capital Investment	**750**	743	**2,265**	2,364
Acquisitions	**-**	1	**17**	5
Divestitures	**(235)**	(241)	**(276)**	(242)
Net Capital Investment [(1)]	**515**	503	**2,006**	2,127

(1) Includes expenditures on PP&E and E&E.

Oil Sands capital investment in 2014 focused primarily on the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 296 gross stratigraphic test wells.

In 2014, Conventional capital investment focused primarily on tight oil development, facilities work and on the expansion of the polymer flood at Pelican Lake. Spending on natural gas activities continues to be strategically focused on a small number of high return opportunities.

Our capital investment in the Refining and Marketing segment focused on capital maintenance and projects improving refinery reliability and safety in 2014.

Capital investment also includes spending on technology development, which plays an integral role in our business. Having an innovation and technology development strategy that is integrated with our business is vital to our ability to minimize our environmental footprint and execute our projects with excellence. Our teams look for ways to improve existing operations and evaluate new ideas to potentially reduce costs, enhance the recovery techniques we use to access crude oil and natural gas, and improve our refining processes.

Capital investment in our Corporate and Eliminations segment includes spending on corporate assets, such as computer equipment, leasehold improvements and office furniture.

Further information regarding our capital investment can be found in the Reportable Segments section of this MD&A.

Capital Investment Decisions

Our disciplined approach to capital allocation includes prioritizing our uses of cash flow in the following manner:

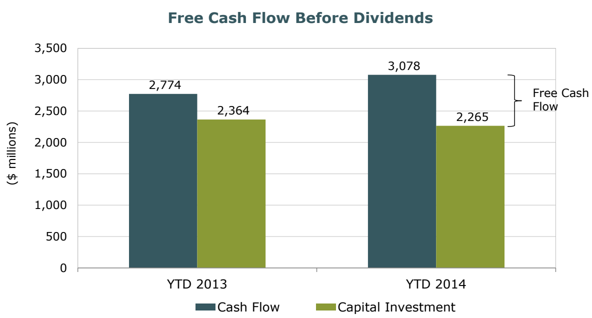
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital, which is the capital spending for projects beyond our committed capital projects.

This capital allocation process includes evaluating all opportunities using specific rigorous criteria as well as achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which allow us to be financially resilient in times of lower cash flow.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Cash Flow [(1)]	**985**	932	**3,078**	2,774
Capital Investment (Committed and Growth)	**750**	743	**2,265**	2,364
Free Cash Flow [(2)]	**235**	189	**813**	410
Dividends Paid	**201**	182	**604**	549
	34	7	**209**	(139)

(1) Non-GAAP measure defined in this MD&A.
(2) Free Cash Flow is a non-GAAP measure defined as Cash Flow less capital investment.

While cash flow from our crude oil, natural gas and refining operations is expected to fund a significant portion of our cash requirements, a portion may be required to be funded through prudent use of balance sheet capacity and management of our asset portfolio.



Approximately two-thirds of our planned 2014 capital investment is for committed capital, which is used to progress approved expansions at Foster Creek and Christina Lake, construction of phase A at Narrows Lake and support existing business operations. The remaining one-third is discretionary capital for activities that include further developing our tight oil opportunities, advancing future oil sands expansions through the regulatory process and investment in technology development. Refer to the Liquidity and Capital Resources section of this MD&A for further discussion.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of Cenovus's bitumen assets at Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. The Athabasca natural gas assets also form part of this segment. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.

Conventional, which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake. This segment also includes the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.

Refining and Marketing, which is focused on the refining of crude oil products into petroleum and chemical products at two refineries located in the U.S. The refineries are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. This segment also markets Cenovus's crude oil and natural gas, as well as third-party purchases and sales of product that provide operational flexibility for transportation commitments, product type, delivery points and customer diversification.

■ Cenovus's major operations   This graphic is for illustration purposes only, Land as at December 31, 2013.

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, research costs and financing activities. As financial instruments are settled, the realized gains and losses are recorded in the operating segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

The operating and reportable segments shown above reflect the change in Cenovus's operating structure adopted for the year ended December 31, 2013; as such, prior periods have been restated. In addition, research activities previously included in operating expense have been reclassified to conform to the presentation adopted for the year ended December 31, 2013.

Revenues by Reportable Segment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Oil Sands	**1,281**	1,060	**3,791**	2,743
Conventional	**742**	746	**2,384**	2,126
Refining and Marketing	**3,144**	3,459	**9,885**	9,483
Corporate and Eliminations	**(197)**	(190)	**(656)**	(442)
	4,970	5,075	**15,404**	13,910

OIL SANDS

In northeastern Alberta, we are a 50 percent partner in the Foster Creek, Christina Lake and Narrows Lake oil sands projects. We have several emerging projects in the early stages of assessment, including our 100 percent-owned projects at Telephone Lake and Grand Rapids. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Significant factors that impacted our Oil Sands segment in the third quarter of 2014 compared with 2013 include:

- First production at Foster Creek phase F in September, beginning the approximate eighteen month ramp up;
- Christina Lake production increasing 30 percent, to an average of 68,458 barrels per day, with phase E reaching nameplate production capacity in the second quarter of 2014;
- Commencing a small-scale planned turnaround at Foster Creek; and
- Foster Creek production averaging 56,631 barrels per day, slightly higher than our expectations, as a result of more wedge wells coming on stream, partially offset by a higher steam to oil ratio ("SOR").

Oil Sands – Crude Oil

Financial Results

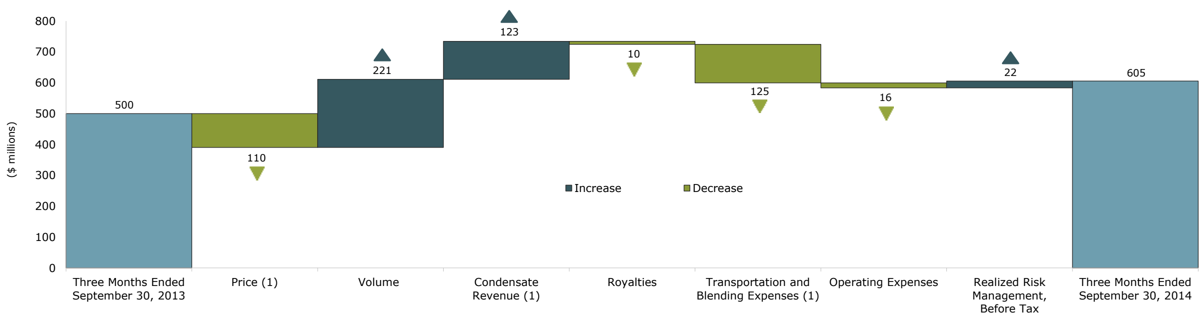
($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Gross Sales	**1,334**	1,100	**3,909**	2,797
Less: Royalties	**62**	52	**180**	93
Revenues	**1,272**	1,048	**3,729**	2,704
Expenses				
Transportation and Blending	**518**	393	**1,636**	1,231
Operating	**147**	131	**483**	386
(Gain) Loss on Risk Management	**2**	24	**59**	(3)
Operating Cash Flow (1)	**605**	500	**1,551**	1,090
Capital Investment	**493**	425	**1,488**	1,380
Operating Cash Flow Net of Related Capital Investment	**112**	75	**63**	(290)

(1) Non-GAAP measure defined in this MD&A.

Capital investment in excess of Operating Cash Flow is funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments.

Three Months Ended September 30, 2014 Compared With September 30, 2013

Operating Cash Flow Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Pricing

In the third quarter, our average crude oil sales price was $71.82 per barrel, a 12 percent decline from 2013. This is consistent with the decline of the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 23 percent, to a discount of US$3.91 per barrel (2013 – US$5.08 per barrel), primarily due to improved pipeline access to the U.S. Gulf Coast and increased rail take-away capacity resulting in greater access to refineries that can process heavier crude oil. In the third quarter, 64,042 barrels per day of Christina Lake production was sold as CDB (2013 – 44,990 barrels per day), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	2014	Percent Change	2013
	Three Months Ended September 30,		
Foster Creek	**56,631**	**15%**	49,092
Christina Lake	**68,458**	**30%**	52,732
	125,089	**23%**	101,824

Christina Lake production increased primarily as a result of phase E reaching nameplate production capacity in the second quarter of 2014 and the total facility operating at approximately 99 percent of capacity. In addition, in the same period last year there was unplanned minor downtime related to phase E start-up and commissioning.

Foster Creek production increased as a result of more wedge wells coming on stream and a smaller impact on planned turnarounds year over year. The smaller scale 2014 planned turnaround had a 900 barrel per day impact to production as compared to our 2013 planned major turnaround which reduced volumes by 4,400 barrels per day. In addition, performance also improved as we addressed the well maintenance backlog experienced in 2013 and continued to focus on preventative work and subsurface monitoring. In September 2014, we achieved first production from phase F, with ramp up expected to take approximately eighteen months.

Condensate

The bitumen produced by Cenovus must be blended with condensate to reduce its viscosity in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate. As the spread between the WCS benchmark price narrows in relation to the condensate benchmark, we recover a larger proportion of the cost to blend our product. Consistent with the widening of the WCS-Condensate differential, the proportion of the cost of condensate recovered decreased in the third quarter of 2014 compared to 2013.

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price. Royalty calculations differ between properties.

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized prices. Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

(percent)	2014	2013
	Three Months Ended September 30,	
Foster Creek	**7.2**	7.6
Christina Lake	**7.9**	7.0

Royalties increased $10 million in the third quarter of 2014, primarily at Christina Lake from an increase in sales volumes, partially offset by a decline in our realized prices. At Foster Creek, the 2014 royalty calculation was based on net profits as compared to a calculation based on gross revenues in 2013.

Expenses

Transportation and Blending

Transportation and blending costs rose $125 million or 32 percent. Blending costs rose $123 million primarily due to an increase in condensate volumes, consistent with the rise in production. Transportation charges increased $2 million primarily due to higher production and higher volumes shipped by unit trains.

Operating

Our operating costs for the third quarter were primarily for workforce, fuel, and repairs and maintenance. In total, operating costs increased $16 million and decreased on a per-barrel basis to $12.41 per barrel.

Per-unit Operating Costs

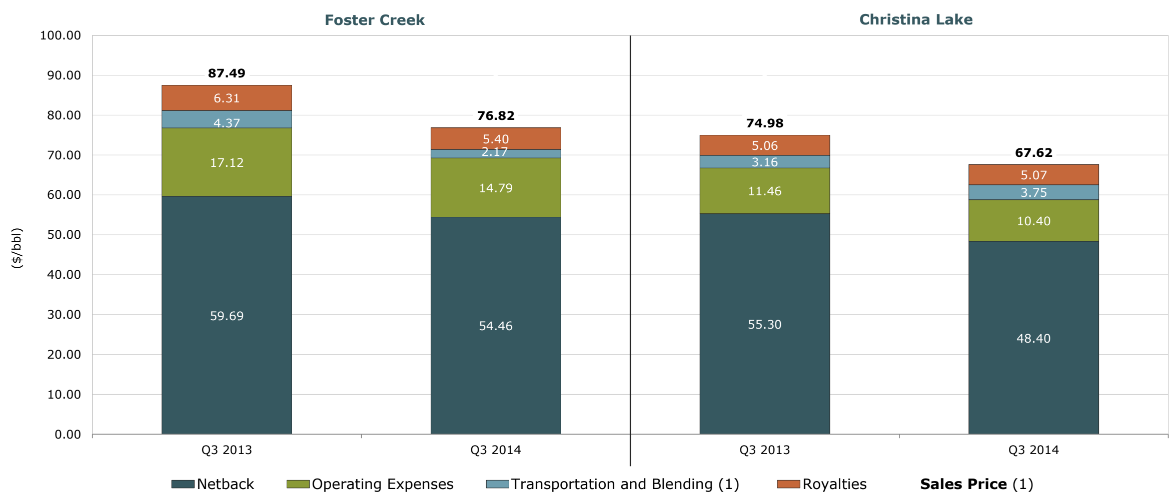
	Three Months Ended September 30,		
($/bbl)	2014	Percent Change	2013
Foster Creek			
Fuel	**4.31**	**74%**	2.47
Non-fuel	**10.48**	**(28)%**	14.65
Total	**14.79**	**(14)%**	17.12
Christina Lake			
Fuel	**3.32**	**35%**	2.46
Non-fuel	**7.08**	**(21)%**	9.00
Total	**10.40**	**(9)%**	11.46

In the third quarter, Foster Creek non-fuel operating costs declined $4.17 per barrel. Costs associated with workover activities decreased compared with 2013 when we were addressing a backlog of well maintenance. In addition, after a review of our 2014 re-drilling program at Foster Creek, it was determined that these activities were beyond normal maintenance and, in fact, enhanced future production capability and were normal capital expenditures. As a result, these costs, which had been previously recognized as operating costs, have now been capitalized in the third quarter. This reduced operating costs by $1.60 per barrel. In addition, per-unit operating costs decreased compared to 2013 and the first and second quarters of 2014 due to the rise in production. We anticipate full year operating costs to be in-line with expectations.

Fuel costs continue to have a significant impact on our per unit operating costs increasing $1.84 per barrel. The increase is due to higher natural gas prices, consistent with the rising benchmark AECO price, and higher consumption, consistent with the increase in the SOR.

Christina Lake operating costs declined $1.06 per barrel in the quarter. Non-fuel operating costs decreased $1.92 per barrel, primarily due to an increase in production, the total facility operating at approximately 99 percent of capacity and a decline in fluid, waste handling and trucking costs related to the optimization of the chemical application process, partially offset by an increase in workover activities related to well servicing. Fuel costs increased by $0.86 per barrel due a rise in natural gas prices.

Operating Netbacks



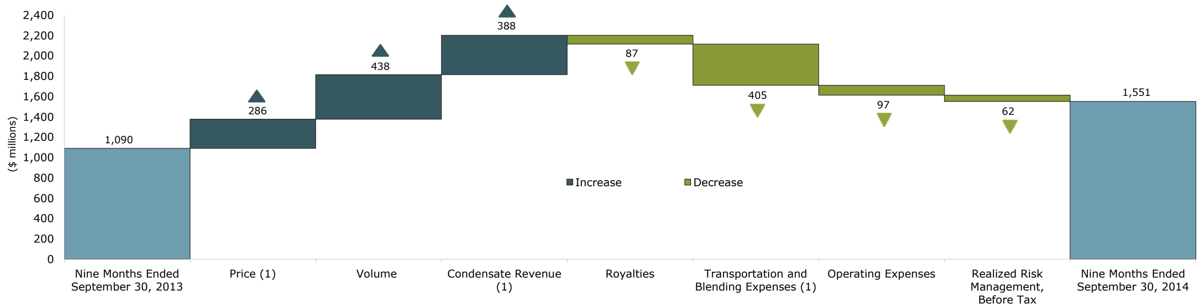
(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the third quarter was $38.50 per barrel (2013 – $38.85 per barrel) for Foster Creek and $42.57 per barrel (2013 – $39.86 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.*

Risk Management

Risk management activities resulted in realized losses of $2 million in the third quarter of 2014 (2013 – realized losses of $24 million), consistent with average benchmark prices exceeding our contract prices.

Nine Months Ended September 30, 2014 Compared With September 30, 2013

Operating Cash Flow Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Pricing

For the nine months ended September 30, 2014, our average crude oil sales price was $70.96 per barrel, up 14 percent from 2013. This is consistent with the increase in the WCS benchmark price, the strengthening of the CDB price and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 29 percent, to a discount of US$4.38 per barrel (2013 – US$6.14 per barrel). Year to date, 57,659 barrels per day of Christina Lake production was sold as CDB (2013 – 38,532 barrels per day), with the remainder sold into the WCS stream.

Production Volumes

	Nine Months Ended September 30,		
(barrels per day)	**2014**	**Percent Change**	2013
Foster Creek	**56,070**	**5%**	53,450
Christina Lake	**67,400**	**49%**	45,211
	123,470	**25%**	98,661

The substantial increase in production at Christina Lake resulted from phase E reaching nameplate production capacity in the second quarter of 2014 and improved performance of our facilities. We completed a planned partial turnaround in the second quarter of 2014 which had a minimal impact on production as volumes from phases A and B were processed through the phase C, D and E plant. In 2013, a planned full turnaround was performed. Production increased at Foster Creek, slightly higher than our expectations as previously discussed.

Condensate

As the WCS benchmark price narrows in relation to the Condensate benchmark, we recover a larger proportion of the cost to blend our product. The proportion of the cost of condensate recovered increased on a year-to-date basis compared to 2013, consistent with the narrowing of the WCS-Condensate differential.

Royalties

	Nine Months Ended September 30,	
(percent)	**2014**	2013
Foster Creek	**8.2**	5.7
Christina Lake	**7.6**	6.4

Royalties increased $87 million in 2014 primarily related to higher realized prices and an increase in sales volumes at both of our properties, and an increase in the Canadian dollar WTI Benchmark price. At Foster Creek, the 2014 royalty calculation was based on net profits as compared to a calculation based on gross revenues in 2013.

Expenses

Transportation and Blending

Transportation and blending costs rose $405 million or 33 percent year to date. Blending costs rose $388 million primarily due to an increase in condensate volumes, consistent with the rise in production. Transportation charges were $17 million higher primarily due to production increases.

Operating

In the first nine months of 2014, operating costs were primarily for fuel, workforce and workover activities. In total, operating costs increased $97 million, but decreased on a per-barrel basis to $14.51 per barrel, consistent with the increase in production.

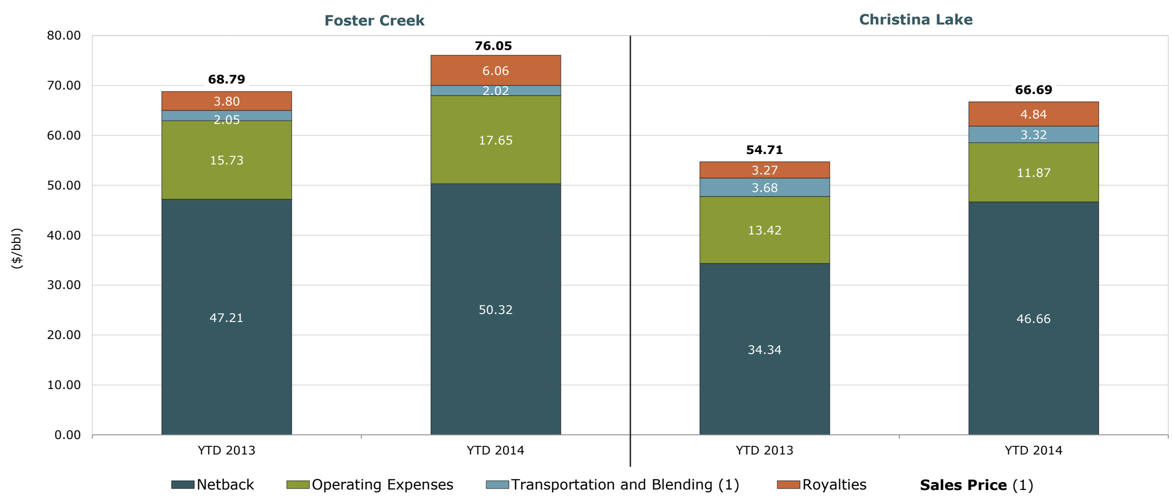
Per-unit Operating Costs

	Nine Months Ended September 30,		
($/bbl)	**2014**	**Percent Change**	2013
Foster Creek			
Fuel	**4.77**	**74%**	2.74
Non-fuel	**12.88**	**(1)%**	12.99
Total	**17.65**	**12%**	15.73
Christina Lake			
Fuel	**3.98**	**27%**	3.13
Non-fuel	**7.89**	**(23)%**	10.29
Total	**11.87**	**(12)%**	13.42

Foster Creek operating costs rose $1.92 per barrel primarily due to higher fuel prices and consumption consistent with a higher SOR, an increase in workforce costs, and higher electricity costs primarily due to an increase in price, partially offset by lower costs related to workover activities.

Christina Lake operating costs decreased $1.55 per barrel primarily due to our production growth, improved performance at our facilities and a decline in fluid, waste handling and trucking costs related to the optimization of the chemical application process. Decreases were offset by an increase in the price of fuel and higher workover activities related to well servicing. Fuel consumption declined on a per-barrel basis consistent with the decrease in SOR.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate for the nine months ended September 30, 2014 was $44.49 per barrel (2013 – $42.61 per barrel) for Foster Creek and $48.02 per barrel (2013 – $45.80 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

Risk Management

Risk management activities resulted in realized losses of $59 million in the first nine months of 2014 (2013 – realized gains of $3 million), consistent with average benchmark prices exceeding our contract prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operation in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production, net of internal usage, for the three and nine months ended September 30, 2014 remained consistent at 23 MMcf per day and 22 MMcf per day, respectively (2013 – 23 MMcf per day and 21 MMcf per day, respectively). Operating Cash Flow was $5 million in the third quarter of 2014 (2013 – $3 million) and $43 million on a year-to-date basis (2013 – $13 million). The increases were due to higher realized natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Foster Creek	**207**	205	**637**	604
Christina Lake	**198**	162	**563**	499
	405	367	**1,200**	1,103
Narrows Lake	**38**	40	**130**	90
Telephone Lake	**23**	1	**94**	71
Grand Rapids	**20**	6	**36**	32
Other [1]	**8**	12	**32**	87
Capital Investment [2]	**494**	426	**1,492**	1,383

(1) Includes new resource plays and Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.

Existing Projects

Capital investment at Foster Creek in 2014 focused on expansion phases F, G and H, offsite facility work related to phases G and H, drilling of sustaining wells, and operational improvement projects. Capital investment increased in the third quarter and on a year-to-date basis due to higher spending on offsite facilities, drilling and completions on well pairs and wells using our Wedge Well™ technology, partially offset by a decrease in spending on plant facilities and operational improvement projects.

In 2014, Christina Lake capital investment focused on expansion phases F and G, phase E well pad and offsite facility construction, and sustaining well programs including the use of our Wedge Well™ technology. Capital investment increased in the third quarter and on a year-to-date basis due to sustaining well programs including our Wedge Well™ technology, and phases F and G plant engineering, procurement and construction, partially offset by lower spending on phase E plant construction.

Capital investment at Narrows Lake declined slightly in the third quarter of 2014 and increased on a year-to-date basis, as spending continued on phase A engineering, procurement, and plant construction. Spending on phase A started in the third quarter of 2013.

Emerging Projects

In 2014, Telephone Lake capital investment was primarily focused on the preliminary engineering work on the central processing facility, costs related to the dewatering pilot project and the drilling of stratigraphic test wells. Capital spending in the third quarter and on a year-to-date basis increased as a result of our summer stratigraphic well program using our SkyStrat™ drilling rig, which focused on recently acquired acreage adjacent to the central processing facility site.

Capital investment at Grand Rapids in 2014 was primarily focused on costs related to the pilot project and the drilling of stratigraphic test wells. In the first quarter of 2014, we received regulatory approval for a 180,000 barrel per day commercial SAGD operation. Capital investment increased in the three and nine months ended September 30, 2014 due to the dismantling and removal of the Joslyn facility to be installed at Grand Rapids.

Drilling Activity

Consistent with our strategy to further delineate our resources, we completed another stratigraphic test well program over the winter drilling season.

Nine Months Ended September 30,	Gross Stratigraphic Test Wells [1] 2014	2013	Gross Production Wells [2] [3] 2014	2013
Foster Creek	**147**	111	**61**	31
Christina Lake	**52**	69	**40**	18
	199	180	**101**	49
Narrows Lake	**22**	26	**-**	-
Telephone Lake	**45**	28	**-**	-
Grand Rapids	**9**	1	**-**	-
Other	**21**	96	**-**	-
	296	331	**101**	49

(1) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the nine months ended September 30, 2014, we drilled 14 wells (2013 – 24 wells).
(2) SAGD well pairs are counted as a single producing well.
(3) Includes wells drilled using our Wedge Well™ technology.
(4) In addition to the drilling activity noted above, we drilled three gross service wells in the nine months ended September 30, 2014 (2013 – 23 gross service wells).

Future Capital Investment

Foster Creek is currently producing from phases A through F. First production from phase F started in September 2014 and the ramp-up is expected to take approximately eighteen months. Expansion work is underway at phases G and H. Foster Creek capital investment for 2014 is forecast to be between $825 million and $845 million and is primarily focused on expansion phases, sustaining wells and operational improvement projects. Expansion work at phases G and H is proceeding as planned. We expect phases G and H to each add initial design capacity of 30,000 barrels per day. We will continue to focus on optimizing production performance and monitoring our long-term reservoir management plan. Start-up of first steam from phases G and H is anticipated in 2015 and 2016, respectively. We submitted a joint application and environmental impact assessment ("EIA") to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first half of 2015. In the second quarter of 2014, we received regulatory approval for a Foster Creek development area expansion.

Christina Lake is producing from phases A through E. Expansion work is currently underway for phase F, including cogeneration, and phase G, with added production capacity expected in 2016 and 2017, respectively. Christina Lake capital investment in 2014 is forecast to be between $785 million and $805 million and is primarily focused on expansion phases F and G, the phase C, D and E optimization program, and drilling and facilities work for sustaining well programs including our Wedge Well™ technology. Phase E development spending for well pad and facility construction is expected to continue to the end of 2014. Expansion work on phases F, including cogeneration, and G is continuing as planned and we expect to add gross production capacity of 50,000 barrels per day from each phase. We submitted a joint application and EIA to regulators in the first quarter of 2013 for the phase H expansion, a 50,000 barrel per day phase, for which we expect to receive regulatory approval in the first quarter of 2015.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, for 130,000 barrels per day of capacity and final partner approval in December 2012 for phase A. Construction of the phase A plant commenced in August 2013. Capital investment at Narrows Lake is forecast to be between $185 million and $190 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for phase A, and infrastructure for a construction camp.

Two of our emerging projects are Telephone Lake, located within the Borealis region, and Grand Rapids, located in the Greater Pelican region. We own a 100 percent interest in both projects. Capital investment of approximately $220 million to $230 million in 2014 is expected for our emerging oil sands projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and Grand Rapids, as well as costs related to the pilot project at Grand Rapids. At Grand Rapids, we received regulatory approval in March 2014 for a 180,000 barrel per day commercial SAGD operation. We plan to develop Grand Rapids through a series of expansion phases. Phase A is expected to produce between 8,000 and 10,000 barrels per day, with first steam planned in 2017. The project will benefit from the purchase of an existing facility that will be relocated to the Grand Rapids project site. We continue to operate a SAGD pilot project to gather additional information on the reservoir. At Telephone Lake, we are advancing the regulatory application for the project and anticipate receiving approval in the fourth quarter of 2014. The first two phases of the project are anticipated to have a production capacity of 90,000 barrels per day.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves as estimated by our independent qualified reserves evaluators. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

The following calculation illustrates how the implied depletion rate for our upstream assets could be determined using the reported consolidated data:

($ millions, unless otherwise indicated)	As at December 31, 2013
Upstream Property, Plant and Equipment	13,692
Estimated Future Development Capital	17,795
Total Estimated Upstream Cost Base	31,487
Total Proved Reserves (MBOE)	2,284
Implied Depletion Rate ($/BOE)	13.79

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $15.50 to $16.00 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis.

As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the three and nine months ended September 30, 2014, Oil Sands DD&A increased $55 million and $146 million, respectively. The increases were due to higher sales volumes and higher DD&A rates for both of our properties from additional expenditures and a rise in future development costs associated with total proved reserves.

CONVENTIONAL

Our Conventional operations include predictable cash flow producing crude oil and natural gas assets in Alberta and Saskatchewan, including a carbon dioxide enhanced oil recovery project in Weyburn, the heavy oil assets at Pelican Lake and developing tight oil assets in Alberta. Pelican Lake produces conventional heavy oil using polymer flood technology. The established assets in this segment are strategically important for their long life reserves, stable operations and diversity of crude oil produced.

Furthermore, we own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Fee lands where we have maintained a working interest are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners. Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In the first nine months of 2014, we had approximately 7,700 barrels of oil equivalent per day of royalty interest production from fee lands which resulted in Operating Cash Flow of $122 million. Production from fee lands comprises approximately 50 percent of our total conventional production.

Our natural gas production acts as an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment.

Significant factors that impacted our Conventional segment in the third quarter of 2014 compared with 2013 include:

- Crude oil production averaging 74,000 barrels per day. Increased production from successful horizontal well performance in southern Alberta was offset by a slight decline in production at Pelican Lake as a result of a planned turnaround, expected natural declines and the sale of certain Bakken assets; and
- Generating Operating Cash Flow net of related capital investment of $280 million, an increase of 20 percent.

On September 30, 2014, we completed the sale of certain of our Wainwright assets in Alberta, with an unrelated third party, for net proceeds of $234 million. A gain on disposition of $137 million was recorded on the sale. Crude oil production from these assets was 2,757 barrels per day in the third quarter of 2014 and 2,775 barrels per day on a year-to-date basis (Q3 2013 – 2,617 barrels per day and year to date 2013 – 2,579 barrels per day).

In April 2014, we sold certain of our Bakken assets in southeastern Saskatchewan for net proceeds of $35 million. A gain on disposition of $16 million was recorded on the sale. Prior to the sale, crude oil production from these Bakken assets was 396 barrels per day in the first quarter of 2014 (Q3 2013 – 463 barrels per day and year to date 2013 – 617 barrels per day).

In both the sales transactions completed in 2014, we have retained ownership of mineral interests in the applicable fee lands and receive a royalty on current and future production from all associated fee lands.

In July 2013, we sold our Lower Shaunavon asset for net proceeds of $241 million. There were no production volumes associated with Lower Shaunavon in the third quarter of 2013. Production averaged 2,807 barrels per day in the first nine months of 2013.

Conventional – Crude Oil

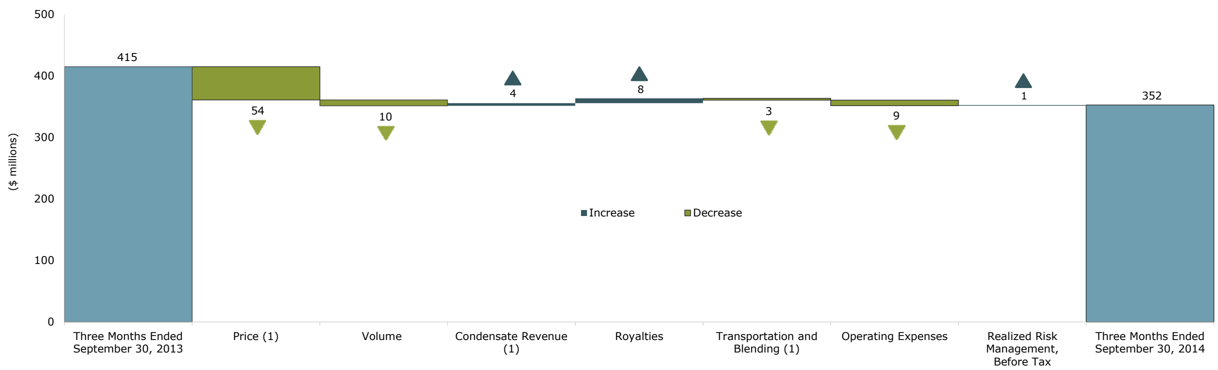
Financial Results

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Gross Sales	**619**	679	**1,978**	1,829
Less: Royalties	**58**	66	**174**	156
Revenues	**561**	613	**1,804**	1,673
Expenses				
Transportation and Blending	**69**	66	**249**	235
Operating	**124**	115	**402**	369
Production and Mineral Taxes	**10**	10	**28**	28
(Gain) Loss on Risk Management	**6**	7	**38**	(23)
Operating Cash Flow (1)	**352**	415	**1,087**	1,064
Capital Investment	**189**	270	**601**	841
Operating Cash Flow Net of Related Capital Investment	**163**	145	**486**	223

(1) Non-GAAP measure defined in this MD&A.

Three Months Ended September 30, 2014 Compared With September 30, 2013

Operating Cash Flow Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Pricing

Our average crude oil sales price in the quarter decreased nine percent to $84.94 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

(barrels per day)	Three Months Ended September 30, 2014	Percent Change	2013
Pelican Lake	**24,196**	**(3)%**	24,826
Other Heavy Oil	**14,900**	**(4)%**	15,507
Total Heavy Oil	**39,096**	**(3)%**	40,333
Light and Medium Oil	**33,548**	**-%**	33,651
NGLs	**1,356**	**20%**	1,130
	74,000	**(1)%**	75,114

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, a slight decrease in production at Pelican Lake and the divestiture of our Bakken assets. The increase in production at Pelican Lake related to additional infill wells coming on stream and an increased response from the polymer flood program was offset by the planned turnaround, which reduced our volumes by 1,300 barrels per day.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate. The proportion of the cost of condensate recovered decreased, consistent with the widening of the WCS-Condensate differential.

Royalties

Royalties decreased $8 million primarily due to a decline in sales volumes and lower realized prices.

Royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs. In 2014 and 2013, the Pelican Lake royalty calculation was based on gross revenues. Our other conventional crude oil producing assets are located primarily on crown or fee lands. Production from fee lands results in mineral tax recorded within production and mineral taxes.

In the third quarter of 2014, the effective crude oil royalty rate for all of our Conventional properties was 10.8 percent (2013 – 10.8 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $3 million in the third quarter of 2014, primarily due to higher condensate volumes and price. Transportation costs remained relatively consistent compared to 2013.

Operating

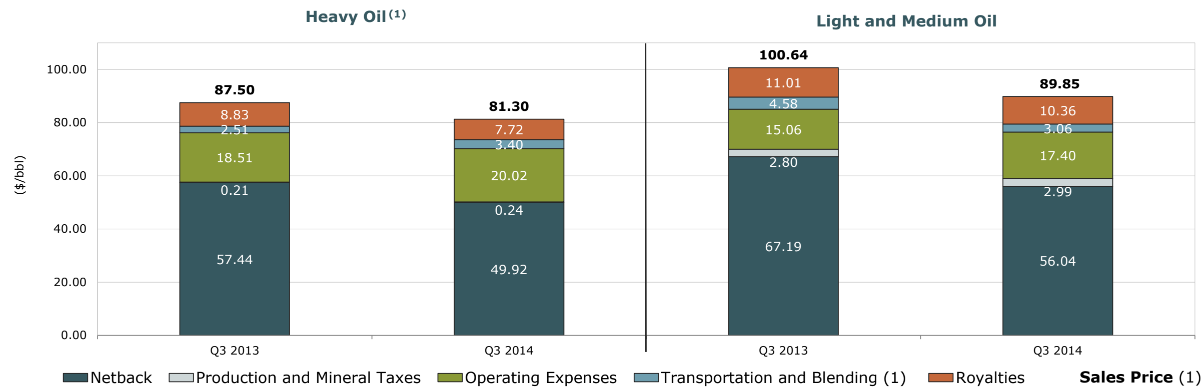
Primary drivers of our operating costs in the third quarter of 2014 were for workover activities, workforce, repairs and maintenance, electricity and chemical consumption. Our operating costs increased $9 million to $18.45 per barrel.

Operating costs increased $1.78 per barrel, primarily due to:

- Higher fluid, waste handling and trucking costs as a result of new wells coming on stream;
- A rise in chemical costs from higher polymer prices and increased consumption related to our polymer flood programs, partially offset by a decline in chemicals used as a result of the planned turnaround at Pelican Lake; and
- An increase in property tax and surface lease rentals associated with new wells, pipelines and infrastructure.

The increases in our operating costs were partially offset by declines due to the sale of our Bakken assets, in addition to lower workover and electricity costs.

Operating Netbacks



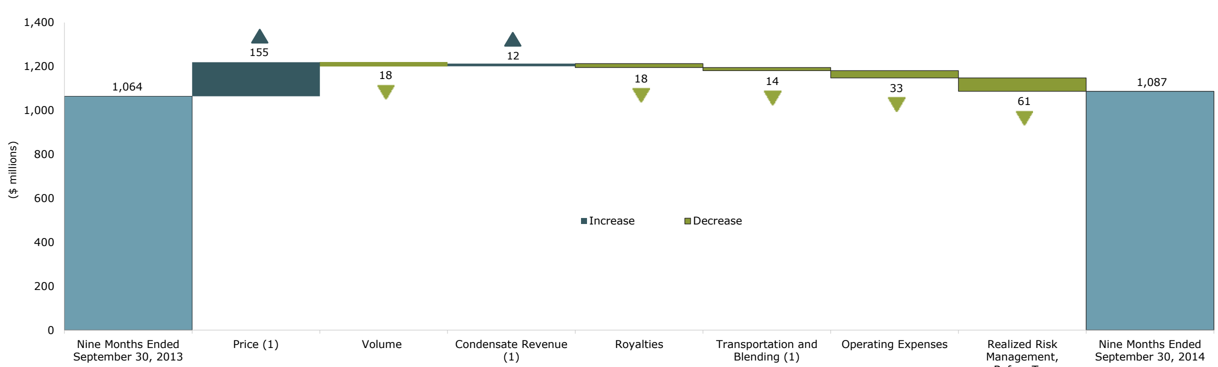
(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $13.25 per barrel in the third quarter (2013 – $11.65 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

Risk management activities in the third quarter resulted in realized losses of $6 million (2013 – realized losses of $7 million), consistent with average benchmark prices exceeding our contract prices.

Nine Months Ended September 30, 2014 Compared With September 30, 2013

Operating Cash Flow Variance



(1) Revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.

Revenues

Pricing

In the first nine months of the year, our average crude oil sales price increased nine percent to $86.82 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

	Nine Months Ended September 30,		
(barrels per day)	**2014**	**Percent Change**	2013
Pelican Lake	**24,593**	**2%**	24,162
Other Heavy Oil	**15,467**	**(4)%**	16,163
Total Heavy Oil	**40,060**	**(1)%**	40,325
Light and Medium Oil	**34,488**	**(4)%**	36,081
NGLs	**1,200**	**18%**	1,018
	75,748	**(2)%**	77,424

Increased production related to our successful horizontal well performance in southern Alberta and higher production at Pelican Lake, was offset by expected natural declines and the sale of our Lower Shaunavon and Bakken assets. Production increased at Pelican Lake as a result of an increased response from the polymer flood program and additional infill wells coming on stream, partially offset by the planned turnaround in 2014.

Condensate

On a year-to-date basis, the proportion of the cost of condensate recovered increased, consistent with the narrowing of the WCS-Condensate differential.

Royalties

Royalties increased $18 million largely due to an increase in the Canadian dollar equivalent WTI benchmark price, higher realized prices and a rise in sales volumes at Pelican Lake, partially offset by lower sales volumes at our other conventional properties. The effective crude oil royalty rate during the first nine months of the year was 10.2 percent (2013 – 9.8 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $14 million in the first nine months of the year. The cost of condensate increased by $12 million as a result of higher prices. Transportation costs rose $2 million due to higher pipeline and storage costs related to our Pelican Lake property, partially offset by reduced transportation costs from lower sales volumes at our other conventional properties.

Operating

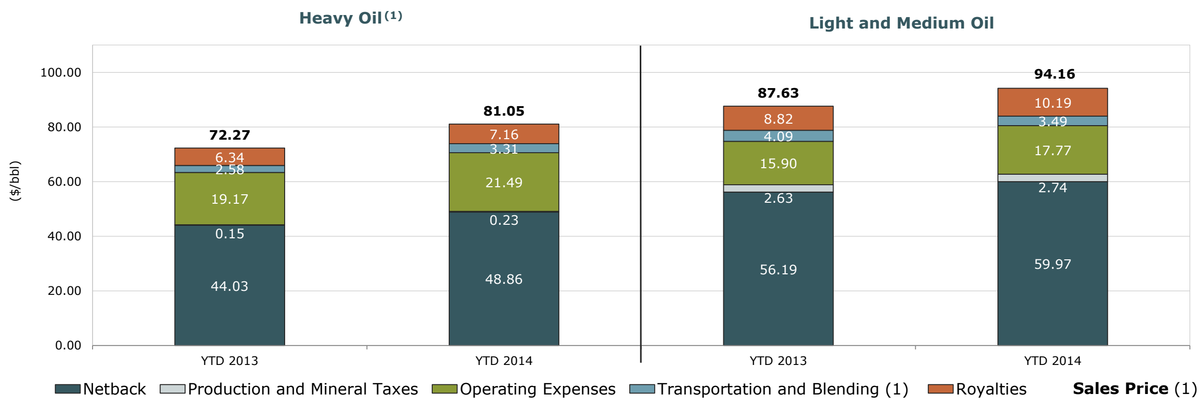
Year to date, operating costs were predominantly composed of workover activities, workforce, electricity costs and repairs and maintenance. Operating costs rose $33 million to $19.47 per barrel.

Operating costs increased $2.09 per barrel, primarily due to:

- Increased repairs and maintenance and workover activities related to well optimizations;
- Higher chemical costs associated with polymer consumption and price related to the polymer flood programs; and
- Higher fluid, waste handling and trucking costs as a result of new wells.

Higher crude oil operating costs were partially offset by declines in operating costs due to the sale of Lower Shaunavon and Bakken assets, in addition to lower electricity costs.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $16.23 per barrel on a year-to-date basis (2013 – $15.42 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

In the first nine months of the year, risk management activities resulted in realized losses of $38 million (2013 – realized gains of $23 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Gross Sales	**182**	130	**580**	449
Less: Royalties	**4**	2	**10**	6
Revenues	**178**	128	**570**	443
Expenses				
Transportation and Blending	**5**	4	**14**	15
Operating	**51**	50	**152**	157
Production and Mineral Taxes	**2**	1	**8**	2
(Gain) Loss on Risk Management	**(4)**	(18)	**(3)**	(45)
Operating Cash Flow (1)	**124**	91	**399**	314
Capital Investment	**9**	5	**20**	17
Operating Cash Flow Net of Related Capital Investment	**115**	86	**379**	297

(1) Non-GAAP measure defined in this MD&A.

Operating Cash Flow from natural gas continues to help fund growth opportunities in our Oil Sands segment.

Three and Nine Months Ended September 30, 2014 Compared With September 30, 2013

Revenues

Pricing

Our average natural gas sales price increased in 2014 consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased seven percent to 466 MMcf per day in the third quarter of 2014 and declined nine percent to 469 MMcf per day on a year-to-date basis, primarily due to expected natural declines.

Royalties

Royalties increased in the third quarter of 2014 and on a year-to-date basis, as a result of higher prices, despite production declines. The average royalty rate in the third quarter was 2.0 percent (2013 – 1.8 percent) and 1.7 percent (2013 – 1.5 percent) on a year-to-date basis. Most of our natural gas production is located on fee lands where we hold mineral rights, which results in mineral tax being recorded within production and mineral taxes.

Expenses

Operating

In 2014, our operating expenses were primarily composed of property taxes and lease costs, workforce and repairs and maintenance. During the quarter, operating expenses remained relatively consistent. On a year-to-date basis, operating expenses decreased $5 million due to natural production declines, a decrease in electricity pricing and consumption, and lower workforce costs, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities resulted in realized gains of $4 million in the third quarter and $3 million on a year-to-date basis (2013 – realized gains of $18 million and $45 million, respectively), consistent with our contract prices exceeding the average benchmark price.

Conventional – Capital Investment [1]

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Pelican Lake	**61**	97	**200**	348
Other Heavy Oil	**15**	33	**64**	104
Light and Medium Oil	**113**	140	**337**	389
Natural Gas	**9**	5	**20**	17
	198	275	**621**	858

(1) *Includes expenditures on PP&E and E&E assets.*

Capital investment in the first nine months of 2014 was primarily composed of spending on tight oil development and facilities work. At Pelican Lake, capital investment focused on infill drilling, maintenance capital and facilities upgrades associated with the expansion of the polymer flood. Spending on natural gas activities continues to be managed in response to the natural gas price environment.

The decline in capital investment at Pelican Lake reflects our decision to align spending with the more moderate production ramp-up associated with the results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	Nine Months Ended September 30, 2014	2013
Crude Oil	**101**	155
Recompletions	**620**	649
Gross Stratigraphic Test Wells	**18**	38
Other [1]	**34**	58

(1) *Includes dry and abandoned, observation and service wells.*

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are primarily related to lower-risk Alberta coal bed methane development.

Future Capital Investment

In 2014, Pelican Lake capital investment is forecast to be between $250 million and $255 million with spending mainly focused on infill drilling, pipeline construction and maintenance capital for the polymer flood.

Capital investment on other Conventional crude oil properties, which will be focused on tight oil development and facilities work, is forecast to be between $580 million and $590 million.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves as estimated by our independent qualified reserves evaluators. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

Conventional DD&A decreased $12 million and $112 million for the three and nine months ended September 30, 2014, respectively. In the third quarter, the decline was due to a decrease in sales volumes and lower DD&A rates from a decline in expenditures. On a year-to-date basis, the decrease was due to the impairment loss recorded in 2013, a decline in sales volumes and lower DD&A rates from a decline in expenditures and the Lower Shaunavon disposition.

REFINING AND MARKETING

We are a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. Our Refining and Marketing segment allows us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated strategy provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to our refineries. The Refining and Marketing segment's results are affected by changes in the U.S./Canadian dollar exchange rate.

Significant factors that impacted our Refining and Marketing segment in the third quarter of 2014 compared with 2013 include:

- Crude oil runs and refined product output decreased as a result of an unplanned coker outage at our Borger refinery in July 2014 and the start of a planned turnaround at our Wood River refinery in September 2014;
- Lower heavy oil feedstock costs and higher average market crack spreads; and
- Operating Cash Flow decreasing 51 percent to $68 million primarily due to declines in refined product output, partially offset by lower heavy crude oil feedstock costs and higher average market crack spreads.

Refinery Operations [1]

	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Crude Oil Capacity [2] (Mbbls/d)	**460**	457	**460**	457
Crude Oil Runs (Mbbls/d)	**407**	464	**424**	440
Heavy Crude Oil	**201**	240	**205**	223
Light/Medium	**206**	224	**219**	217
Refined Products (Mbbls/d)	**429**	487	**446**	461
Gasoline	**230**	244	**228**	230
Distillate	**131**	152	**138**	143
Other	**68**	91	**80**	88
Crude Utilization (percent)	**88**	101	**92**	96

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity of Wood River increased effective January 1, 2014.

On a 100 percent basis, our refineries have capacity of approximately 460,000 gross barrels per day of crude oil, excluding NGLs, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil, and capacity of 45,000 gross barrels per day of NGLs. The ability to refine heavy crude oil demonstrates our ability to economically integrate our heavy crude oil production. The discount of WCS relative to WTI continues to benefit our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In the three months ended September 30, 2014, an unplanned coker outage at our Borger refinery and the start of a planned turnaround at our Wood River refinery significantly reduced crude oil runs, refined product output and crude utilization as compared to 2013. The unplanned outage lasted approximately two weeks.

In the first nine months of the year, our crude oil runs, refined product output and crude utilization decreased as a result of the 2014 outages. In 2013, an unplanned hydrocracker outage at Wood River in the second quarter negatively impacted volumes, however not to the same extent.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. The amount of heavy crude oil processed in 2014 decreased primarily as a result of processing higher volumes of medium crude oil due to more favourable economics.

Financial Results

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Revenues	**3,144**	3,459	**9,885**	9,483
Purchased Product	**2,918**	3,172	**8,836**	8,065
Gross Margin	**226**	287	**1,049**	1,418
Expenses				
Operating	**162**	127	**525**	397
(Gain) Loss on Risk Management	**(4)**	21	**(9)**	29
Operating Cash Flow [1]	**68**	139	**533**	992
Capital Investment	**42**	19	**111**	70
Operating Cash Flow Net of Capital Investment	**26**	120	**422**	922

(1) Non-GAAP measure defined in this MD&A.

Gross Margin

In the third quarter, gross margin declined primarily due to:

- Lower refined product output as a result of the outages discussed above.

The decrease was partially offset by:

- Lower heavy crude oil feedstock costs, consistent with the decline in the WCS benchmark price; and
- Higher average market crack spreads, consistent with the widening of the Brent-WTI differential.

On a year-to-date basis, the decrease in gross margin was primarily due to:

- A decline in market crack spreads, consistent with the narrowing of the Brent-WTI differential;
- Higher heavy crude oil feedstock costs, consistent with the increase in the WCS price; and
- Lower refined product output as discussed above.

Our refineries do not blend renewable fuels into the motor fuel products we produce and consequently we are obligated to purchase Renewable Identification Numbers ("RINs"). In the third quarter of 2014, the cost of our RINs was $29 million (2013 – $55 million). On a year-to-date basis, the cost of our RINs was $85 million (2013 – $132 million). These decreases are consistent with the decline in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating

Primary drivers of operating costs in 2014 were maintenance, labour, utilities and supplies. Operating costs increased 28 percent (year-to-date – 32 percent), primarily due to higher maintenance costs related to both unplanned outages and planned turnaround activities, an increase in utility costs resulting from a rise in natural gas costs, and the change in the US$/C$ foreign exchange rate.

Refining and Marketing – Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Wood River Refinery	**30**	12	**64**	38
Borger Refinery	**12**	7	**47**	32
	42	19	**111**	70

Capital expenditures in 2014 focused on capital maintenance and refinery reliability and safety projects. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We are currently awaiting permit approval, which is anticipated in the first half of 2015, and planned start-up of the project is anticipated in 2016.

In 2014, we expect to invest between $165 million and $175 million mainly related to routine safety initiatives, meeting new low sulphur (Tier III) gasoline requirements and additional capital investments expected to enhance returns at the Wood River Refinery.

DD&A

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased $2 million in the third quarter of 2014 and $14 million on a year-to-date basis, primarily due to the change in the US$/C$ foreign exchange rate.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices and the unrealized mark-to-market gains and losses on the long-term power purchase contract. In the third quarter of 2014, our risk management activities resulted in $165 million of unrealized gains, before tax (2013 – $8 million of unrealized gains, before tax). On a year-to-date basis, risk management activities generated $180 million of unrealized gains, before tax (2013 – $196 million of unrealized losses, before tax). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing activities and research costs.

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
General and Administrative	**80**	103	**291**	268
Finance Costs	**105**	160	**337**	407
Interest Income	**(4)**	(23)	**(31)**	(73)
Foreign Exchange (Gain) Loss, Net	**263**	(55)	**223**	93
Research Costs	**3**	5	**9**	14
(Gain) Loss on Divestiture of Assets	**(137)**	1	**(157)**	1
Other (Income) Loss, Net	**2**	-	**-**	-
	312	191	**672**	710

Expenses

General and Administrative

In 2014, primary drivers of our general and administrative expenses were staffing costs and office rent. General and administrative expenses decreased in the third quarter of 2014 by $23 million primarily due to a decline in long-term incentive costs, consistent with the change in our share price. On a year-to-date basis, general and administrative costs increased $23 million primarily due to higher long-term incentive costs and higher staffing costs.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. Finance costs decreased $55 million and $70 million in the three and nine months ended September 30, 2014, respectively. The decreases were primarily due to a US$32 million premium on the early redemption of senior unsecured notes in the third quarter of 2013 and lower interest incurred on the Partnership Contribution Payable. In the first quarter of 2014, we exercised our right to prepay the Partnership Contribution Payable.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the third quarter was 5.0 percent (2013 – 5.2 percent) and for the nine months ended September 30, 2014 was 5.0 percent (2013 – 5.3 percent).

Foreign Exchange

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Unrealized Foreign Exchange (Gain) Loss	**259**	(48)	**221**	86
Realized Foreign Exchange (Gain) Loss	**4**	(7)	**2**	7
	263	(55)	**223**	93

The majority of unrealized losses in the third quarter of 2014 stem from translation of our U.S. dollar denominated debt.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A for the third quarter was $20 million (2013 – $20 million) and $61 million on a year-to-date basis (2013 – $59 million).

Income Tax Expense (Recovery)

($ millions)	Three Months Ended September 30, 2014	2013	Nine Months Ended September 30, 2014	2013
Current Tax				
Canada	**49**	60	**82**	147
U.S.	**(14)**	(20)	**21**	38
Total Current Tax	**35**	40	**103**	185
Deferred Tax	**144**	132	**396**	211
	179	172	**499**	396
Effective Tax Rate	**33.6%**	31.7%	**29.1%**	35.5%

A provision for income taxes on earnings in the interim periods is accrued using the income tax rate that would be applicable to the expected total annual earnings. Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

The 2014 provision for income tax includes the effect of a favourable adjustment to current tax related to prior years, which has minimal impact on total income tax. In the first nine months of the year, current income tax decreased $82 million primarily due to the favourable adjustment related to prior years and a decrease in U.S. Operating Cash Flow, partially offset by an increase in Conventional Operating Cash Flow. Deferred income tax increased $185 million in the first nine months of the year due to the effect of the favourable adjustment to current tax related to prior years, an increase in Canadian timing differences arising from increased Oil Sands income, and an unrealized risk management gain compared to a loss in the prior year, partially offset by a decrease in U.S. timing differences in 2014 arising from lower U.S. income.

Our effective tax rate is a function of the relationship between total tax expense and the amount of earnings before income taxes. The effective tax rate differs from the Canadian statutory tax rate as it reflects higher U.S. tax rates on U.S. sources of income and permanent differences.

The increase in our effective tax rate in the third quarter of 2014 is due to unrealized foreign exchange losses for which the tax benefit has not been recognized. The decrease on a year-to-date basis is primarily due to lower levels of U.S. source income in the first nine months of 2014 offset by the effect of unrealized foreign exchange losses.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2014**	2013	**2014**	2013
Net Cash From (Used In)				
Operating Activities	**1,092**	840	**2,658**	2,563
Investing Activities	**(463)**	(451)	**(3,552)**	(2,157)
Net Cash Provided (Used) Before Financing Activities	**629**	389	**(894)**	406
Financing Activities	**(232)**	(190)	**(457)**	(539)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(1)**	-	**55**	(3)
Increase (Decrease) in Cash and Cash Equivalents	**396**	199	**(1,296)**	(136)

	As At	
($ millions)	**September 30, 2014**	December 31, 2013
Cash and Cash Equivalents	**1,156**	2,452

Operating Activities

Cash from operating activities was $252 million higher in the third quarter of 2014 primarily due to higher Cash Flow, as discussed in the Financial Results section of this MD&A and an increase in funds from non-cash working capital. Year to date, there was an increase of $95 million in cash from operating activities primarily due to the increase in Cash Flow, as discussed in the Financial Results section of this MD&A, partially offset by a decrease in non-cash working capital.

Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $1,306 million at September 30, 2014 compared to $1,957 million at December 31, 2013. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

Cash used in investing activities in the third quarter of 2014 was $12 million higher (year to date – increase of $1,395 million) due to additional capital expenditures. The year-to-date increase in cash used in investing activities was predominately due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014.

Financing Activities

Our disciplined approach to capital investment decisions means that we prioritize our use of cash flow first to committed capital investment, then to paying a meaningful dividend and finally to growth capital. In the third quarter, we paid a dividend of $0.2662 per share, an increase of 10 percent from 2013 (2013 – $0.242 per share). Year-to-date dividend payments were $604 million (2013 – $549 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

In the third quarter, cash flow used in financing activities increased $42 million primarily due to the net repayment of short-term borrowings and the increase in dividends paid. In the nine months ended September 30, 2014, cash flow used in financing activities declined $82 million as a result of short-term borrowings, partially offset by the increase in dividends paid. Short-term borrowings increased due to the timing of the receipt of proceeds related to the Wainwright disposition.

Our long-term debt was $5,271 million at September 30, 2014 with no principal payments due until October 2019 (US$1.3 billion). The $274 million increase in long-term debt from December 31, 2013 is primarily related to foreign exchange.

As at September 30, 2014, we are in compliance with all of the terms of our debt agreements.

Available Sources of Liquidity

We expect cash flow from our crude oil, natural gas and refining operations to fund a significant portion of our cash requirements over the next decade. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity or management of our asset portfolio. The following sources of liquidity are available as at September 30, 2014.

($ millions)	Amount	Term
Cash and Cash Equivalents	**1,156**	**Not Applicable**
Committed Credit Facility	**2,867**	**November 2017**
U.S. Base Shelf Prospectus [1]	**US$2,000**	**July 2016**
Canadian Base Shelf Prospectus [1]	**1,500**	**July 2016**

(1) Availability subject to market conditions.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper.

On June 24, 2014, we filed a U.S. base shelf prospectus for unsecured notes in the amount of US$2.0 billion, which replaced the U.S. base shelf prospectus dated June 6, 2012, as amended May 9, 2013. The U.S. base shelf prospectus allows for the issuance of debt securities in U.S. dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at September 30, 2014, no notes have been issued under this U.S. base shelf prospectus.

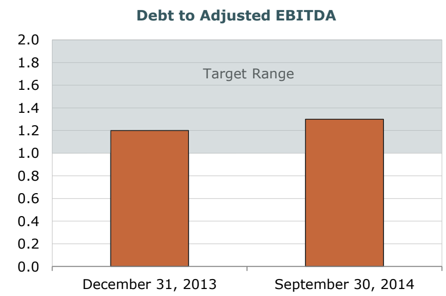
On June 25, 2014, we filed a Canadian base shelf prospectus for unsecured medium term notes in the amount of $1.5 billion, which replaced the Canadian base shelf prospectus dated May 24, 2012. The Canadian base shelf prospectus allows for the issuance of medium term notes in Canadian dollars or other currencies from time to time in one or more offerings. Terms of the notes, including, but not limited to, interest at either fixed or floating rates and maturity dates will be determined at the date of issue. As at September 30, 2014, no medium term notes have been issued under this Canadian base shelf prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt excluding any amounts with respect to the Partnership Contribution Payable or Receivable. We define Capitalization as Debt plus Shareholders' Equity. We define Adjusted EBITDA as earnings before finance costs, interest income, income tax expense, DD&A, asset impairments, unrealized gains (losses) on risk management, foreign exchange gains (losses), gains (losses) on divestiture of assets and other income (loss), net, calculated on a trailing 12 month basis. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	**September 30, 2014**	December 31, 2013
Debt to Capitalization	**33%**	33%
Debt to Adjusted EBITDA (times)	**1.3x**	1.2x

We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At September 30, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the low end of our target ranges. Additional information regarding our financial metrics and capital structure can be found in the notes to the interim Consolidated Financial Statements.



Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares. As at September 30, 2014, no preferred shares were outstanding.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of Cenovus.

In addition to its Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan and two Deferred Share Unit ("DSU") Plans. PSUs are whole share units which entitle the holder to receive upon vesting either a Cenovus common share or a cash payment equal to the value of a Cenovus common share. Refer to the notes of the interim Consolidated Financial Statements for more details.

Total Outstanding Common Shares and Stock-Based Compensation Plans

As at September 30, 2014	Units (thousands)
Common Shares	**757,103**
Stock Options	
NSRs	**41,039**
TSARs	**3,885**
Cenovus Replacement TSARs	**2**
Encana Replacement TSARs	**28**
Other Stock-Based Compensation Plans	
PSUs	**7,121**
DSUs	**1,286**

Contractual Obligations and Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements, debt, future building leases, marketing agreements and capital commitments. In addition, we have commitments related to our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. For further information, see the notes to the interim Consolidated Financial Statements.

Year to date, commitments for various firm transportation agreements increased $6 billion, resulting in total transportation commitments of $27 billion, due to increased costs and tolls on existing commitments. These agreements, some of which are subject to regulatory approval, are for terms of 20 years, subsequent to the date of commencement, and will help align our future transportation requirements with our anticipated production growth.

We have rail loading commitments for 30,000 barrels per day at facilities that are expected to be fully operational by the end of 2014. The degree of utilization of our rail loading capacity is subject to favourable market conditions.

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations and we believe we have made adequate provisions for such claims. There are no individually or collectively significant claims.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2013 annual MD&A.

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. Actively managing these risks improves our ability to effectively execute our business strategy. Our exposure to the risks identified in our 2013 annual MD&A has not changed substantially since December 31, 2013. In addition, no new material risks were identified as at September 30, 2014.

A description of the risk factors and uncertainties affecting Cenovus can be found in the Advisory and a full discussion of the material risk factors affecting Cenovus can be found in our AIF for the year ended December 31, 2013. The following provides an update on our commodity price risk management.

Commodity Price Risk

Fluctuations in commodity prices create volatility in our financial performance. Commodity prices are impacted by a number of factors including global and regional supply and demand, transportation constraints, weather conditions and availability of alternative fuels, all of which are beyond our control and can result in a high degree of price volatility.

We manage our commodity price exposure through a combination of activities including integration, financial hedges and physical contracts. We have a variety of instruments and strategies available to us within our financial hedges and physical contracts, such as swaps, futures, options, collars, differentials and fixed-price contracts, that will be utilized as market conditions warrant. For further details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see the notes to the interim and annual Consolidated Financial Statements. The financial impact is summarized below.

Financial Impact of Risk Management Activities

	Three Months Ended September 30,					
	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**9**	**(159)**	**(150)**	32	(22)	10
Natural Gas	**(5)**	**-**	**(5)**	(19)	15	(4)
Refining	**(4)**	**(7)**	**(11)**	22	(2)	20
Power	**-**	**1**	**1**	(2)	1	(1)
(Gain) Loss on Risk Management	**-**	**(165)**	**(165)**	33	(8)	25
Income Tax Expense (Recovery)	**-**	**43**	**43**	11	(3)	8
(Gain) Loss on Risk Management, After Tax	**-**	**(122)**	**(122)**	22	(5)	17

	Nine Months Ended September 30,					
	2014			2013		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**95**	**(173)**	**(78)**	(22)	147	125
Natural Gas	**(4)**	**(2)**	**(6)**	(46)	51	5
Refining	**(8)**	**(5)**	**(13)**	30	(1)	29
Power	**2**	**-**	**2**	(7)	(1)	(8)
(Gain) Loss on Risk Management	**85**	**(180)**	**(95)**	(45)	196	151
Income Tax Expense (Recovery)	**(21)**	**47**	**26**	(7)	49	42
(Gain) Loss on Risk Management, After Tax	**64**	**(133)**	**(69)**	(38)	147	109

In the quarter, total realized gains or losses on risk management was nil. On a year-to-date basis, realized losses consisted primarily of losses on crude oil financial instruments, consistent with average benchmark prices exceeding our contract prices.

In 2014, we recognized unrealized gains on our crude oil financial instruments as a result of the changes in forward prices compared with prices at the end of the prior year and changes in prices for transactions executed during the period, partially offset by the realization of settled positions and the narrowing of forward light/heavy differentials.

Financial instruments undertaken within our refining segment by the operator, Phillips 66, are primarily for purchased product. Details of contract volumes and prices can be found in the notes to the interim Consolidated Financial Statements.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

For more details regarding our critical accounting judgments, estimates and accounting policies, the following should be read in conjunction with our 2013 annual MD&A.

We are required to make judgments, estimates and assumptions in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from those estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2013.

Critical Accounting Judgments in Applying Accounting Policies

Critical accounting judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recognized in our annual and interim Consolidated Financial Statements and accompanying notes. There have been no changes to our critical judgments used in applying accounting policies in the first nine months of 2014. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2013.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty in the first nine months of 2014. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2013.

Future Accounting Pronouncements

New and Amended Standards and Interpretations Adopted

Offsetting Financial Assets and Financial Liabilities

Effective January 1, 2014, we adopted, as required, amendments to International Accounting Standard 32, *"Financial Instruments: Presentation"* ("IAS 32"). The amendments clarify that the right to offset financial assets and liabilities must be available on the current date and cannot be contingent on a future event. IAS 32 did not impact the consolidated financial statements.

New Standards and Interpretations not yet Adopted

Revenue Recognition

In May 2014, the IASB published IFRS 15, "*Revenue From Contracts With Customers"* ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

The new standard is effective for annual periods beginning on or after January 1, 2017, with earlier adoption permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the consolidated financial statements.

Financial Instruments

On July 24, 2014, the IASB issued IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, *"Financial Instruments: Recognition and Measurement*". IFRS 9 is effective for years beginning on or after January 1, 2018. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. We are currently evaluating the impact of adopting IFRS 9 on the consolidated financial statements.

Additional Standards

A description of additional standards and interpretations that will be adopted by the Company in future periods can be found in the notes to the Consolidated Financial Statements for the year ended December 31, 2013.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

TRANSPARENCY AND CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and to integrating our corporate responsibility principles into the way we conduct our business. We recognize the importance of reporting to stakeholders in a transparent and accountable manner. We disclose not only the information we are required to disclose by legislation or regulatory authorities, but also information that more broadly describes our activities, policies, opportunities and risks.

Our Corporate Responsibility ("CR") policy continues to drive our commitments, our CR approach and reporting, and enables alignment with our business objectives and processes. Our future CR reporting activities will be guided by this policy and will focus on improving performance by continuing to track, measure and monitor our CR performance indicators. Our CR policy and CR report is available on our website at cenovus.com. Our 2013 CR report was issued in July 2014.

In September 2014, our CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the third consecutive year. We were also named to the Dow Jones Sustainability North America Index for the fifth consecutive year.

In June 2014, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the third year in a row and for the fourth consecutive year by Corporate Knights magazine as one of the 2014 Best Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development.

In February 2014, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the second year in a row. In January 2014, Cenovus was included for the first time in the RobecoSAM 2014 Sustainability Yearbook with a Bronze Class distinction. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index. Corporate Knights magazine also named Cenovus to their 2014 Global 100 clean capitalism ranking for the second consecutive year, as announced during the World Economic Forum in Davos, Switzerland in January 2014.

These external recognitions of our commitment to corporate responsibility reaffirm Cenovus's efforts to balance economic, governance, social and environmental performance.

OUTLOOK

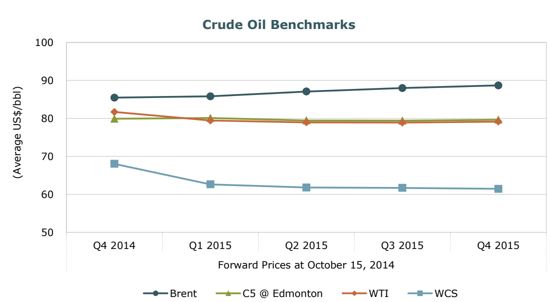
We continue to move forward on our business plan targeting net crude oil production, including our conventional oil operations, of more than 500,000 barrels per day. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects at Telephone Lake and Grand Rapids. We will continue the development of our oil sands resources in multiple phases using a low cost manufacturing-like approach. This approach will be driven by technology, innovation and continued respect for the health and safety of our employees and contractors, with an emphasis on environmental performance and meaningful dialogue with our stakeholders.

The following outlook commentary is focused on the next twelve to fifteen months. The forward pricing outlook for 2015, as of October 15, 2014, has declined significantly from actual pricing in the first half of 2014 and the forward pricing at that time. A key factor that will determine if these lower prices will be realized is whether the Organization of the Petroleum Exporting Countries ("OPEC") responds to the discounted Brent pricing.

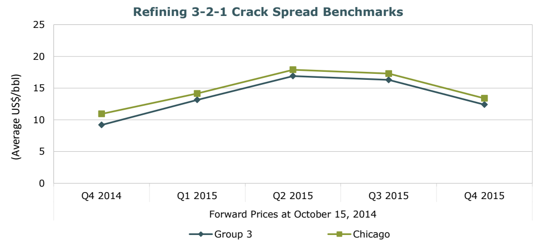
Commodity Prices Underlying our Financial Results

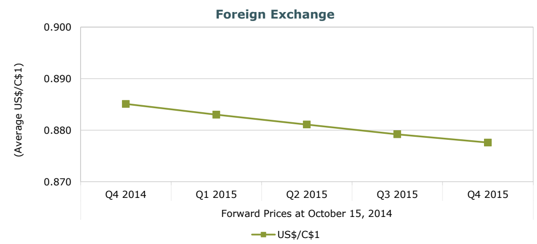
Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will continue to be tied to global economic growth, the pace of North American supply growth, production interruptions and whether OPEC responds to the steep discounts in current market prices by cutting production. Economic indicators suggest an improvement in crude oil demand growth from the U.S. as their economy continues to accelerate. However, comparable economic indicators for the rest of the world show a decline in economic conditions, especially in Europe and China. North American crude oil supply growth is expected to continue at a strong, but moderate pace. Global supply disruptions are difficult to predict and materially impact the price of Brent crude oil. The recent decrease in global crude oil demand offsets the potential for continued supply outages due to uncertainty in Iraq and Libya. Overall, we expect Brent crude oil prices to be lower as compare to the prior twelve to fifteen month period;



- The Brent-WTI differential has narrowed from 2013 as new pipeline capacity from Cushing to the U.S. Gulf Coast has reduced inland congestion. However, growing tight oil supply in the Gulf Coast region should reduce the need for imports to the U.S. and may result in some price volatility as domestic crude oil competes to displace global light and medium crude oil imports. We expect that these supply pressures will result in wider Brent-WTI differentials; and
- The WTI-WCS differential will continue to be set by the marginal transportation cost to the U.S. Gulf Coast. With increased rail infrastructure planned over the coming year, along with incremental pipeline capacity, we expect some level of spare take-away capacity from Alberta. There is likely to be some volatility in the differential due to uncertainty around the timing of new infrastructure, however we expect narrower differentials as compared to the prior twelve to fifteen month period.





With the seasonal reduction in product demand, we expect flat to slight declining of inland refining crack spreads in the near term, as turnaround activity is expected to be near the five year average. Next year, a potential widening of the Brent-WTI differential due to increased domestic crude oil supply would result in improved market crack spreads as compared to the prior twelve to fifteen month period.

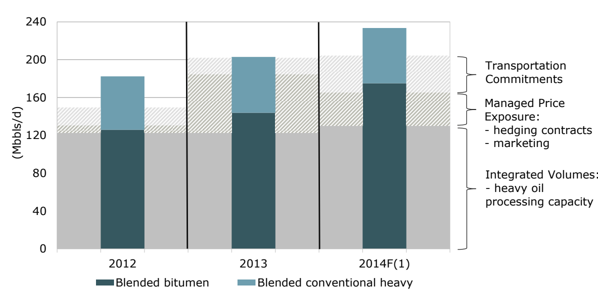
Natural gas prices are expected to remain consistent with prices experienced in the third quarter of 2014, with the potential for volatility based on weather.

Foreign exchange prices have remained consistent in the third quarter of 2014 as compared to the second quarter. The average foreign exchange forward price is US$0.887/C$1 over the next five quarters. The timing of key interest rate decisions, both in Canada and the U.S. in the coming quarters, will dictate momentum. Overall, the Canadian dollar remains relatively weak, which has a positive impact on our revenues and Operating Cash Flow.

Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian congestion. While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity able to process Canadian heavy crudes. From a value perspective, our refining business is able to capture value from both the WTI-WCS differential for Canadian crude and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – protecting our upstream crude oil prices from downside risk by entering into financial transactions that fix the WTI-WCS differential, mitigating the exposure to Canadian congestion;
- Marketing arrangements – protecting our upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments – supporting transportation projects that move crude oil from our production areas to consuming markets and tidewater markets.

Protection Against Canadian Congestion



(1) Expected gross production capacity.

Key Priorities for 2014

Our key priorities for 2014 remain unchanged from 2013.

Market Access

We are focused on near and mid-term strategies to broaden market access for our crude oil production. This will allow us to build on our successful marketing and transportation strategy and broaden the portfolio of market opportunities for our growing production. We have rail loading commitments for 30,000 barrels per day at facilities that are expected to be fully operational by the end of 2014. The degree of utilization of our rail loading capacity is subject to favourable market conditions.

Attacking Cost Structures

We continue to take aim at cost structures across the organization to maintain our track record of cost efficiency. We must ensure that, over the long term, we maintain an efficient and sustainable cost structure and take advantage of our business model. For example, we are actively identifying opportunities in supply chain management to further reduce capital and operating costs.

Other Key Challenges

We will need to effectively manage our business to support our development plans, including securing timely regulatory and partner approvals, complying with environmental regulations and managing competitive pressures within our industry. Additional details regarding the impact of these factors on our financial results are discussed in the Risk Management section of this MD&A.

ADVISORY

Oil and Gas Information

The estimates of reserves and resources data and related information were prepared effective December 31, 2013 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2014 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2013.

Barrels of Oil Equivalent - Certain natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.

Forward-Looking Information

This document contains certain forward-looking statements and other information (collectively "forward-looking information") about our current expectations, estimates and projections, made in light of our experience and perception of historical trends. Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "plan", "forecast" or "F", "target", "project", "could", "focus", "goal", "outlook", "potential", "may", "strategy" or similar expressions and includes suggestions of future outcomes, including statements about our growth strategy and related milestones and schedules, projected future value or net asset value, projections for 2014 and future years, forecast operating and financial results, planned capital expenditures, expected future production, including the timing, stability or growth thereof, expected future refining capacity, expected reserves and contingent and prospective resources, broadening market access, improving cost structures, potential dividends and dividend growth strategy, anticipated timelines for future regulatory, partner or internal approvals, future impact of regulatory measures, forecasted commodity prices, future use and development of technology, including to reduce our environmental impact and projected increasing shareholder value. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally.

The factors or assumptions on which the forward-looking information is based include: assumptions disclosed in our current guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow from operations to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2014 guidance, updated October 23, 2014 and available at cenovus.com, is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$104.00/bbl, WTI of US$97.00/bbl; WCS of US$78.00/bbl; NYMEX of US$4.50/MMBtu; AECO of $4.30/GJ; Chicago 3-2-1 crack spread of US$17.00/bbl; exchange rate of $0.91 US$/C$.

For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00/bbl; WTI of US$100.00-US$106.00/bbl; WCS of US$81.00-US$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of $3.70-$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00/bbl; exchange rate of $1.00 US$/C$; and average diluted number of shares outstanding of approximately 782 million.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments and the success of our hedging strategies; the accuracy of cost estimates; fluctuations in commodity prices, currency and interest rates; fluctuations in product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; maintaining desirable ratios of debt to adjusted EBITDA as well as debt to capitalization; our ability to access various sources of debt and equity capital; accuracy of our reserves, resources and future production estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationships with our partners and to successfully manage and operate our integrated heavy oil business; reliability of our assets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; realized refining and marketing margins; potential failure of new products to achieve acceptance in the market; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of crude oil into petroleum and chemical products; risks associated with technology and its application to our business; the timing and the costs of well and pipeline construction; our ability to secure adequate product transportation, including sufficient crude-by-rail or other alternate transportation; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our consolidated financial statements; changes in the general economic, market and business conditions; the political and economic conditions in the countries in which we operate; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. For a full discussion of our material risk factors, see “Risk Factors” in our AIF or Form 40-F for the year ended December 31, 2013 available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

ABBREVIATIONS

The following is a summary of the abbreviations that have been used in this document:

Crude Oil		**Natural Gas**	
bbl	barrel	Mcf	thousand cubic feet
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
		GJ	Gigajoule

BOE	barrel of oil equivalent
MBOE	thousand barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.