MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED MARCH 31, 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 April 29, 2014, should be read in conjunction with our March 31, 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 April 29, 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 its 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 March 31, 2014, we had a market capitalization of approximately $24 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 for the three months ended March 31, 2014, was in excess of 196,800 barrels per day and our average natural gas production was 476 MMcf per day. Our refinery operations processed an average of 400,000 gross barrels per day of crude oil feedstock into an average of 420,000 gross barrels per day of refined product.

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 continually 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 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:

	Three Months Ended March 31, 2014		
	Ownership Interest (percent)	**Net Production Volumes** (bbls/d)	**Gross Production Volumes** (bbls/d)
Existing Projects			
Foster Creek	50	54,706	109,412
Christina Lake	50	65,738	131,476
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.

Conventional

($ millions)	Three Months Ended March 31, 2014 Crude Oil [1]	Natural Gas
Operating Cash Flow [2]	347	128
Capital Investment	263	7
Operating Cash Flow Net of Related Capital Investment	84	121

(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.

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)	Three Months Ended March 31, 2014
Operating Cash Flow [1]	245
Capital Investment	23
Operating Cash Flow Net of Related Capital Investment	222

(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 the first quarter, we paid a dividend of $0.2662 per share, a 10 percent increase from 2013 (2013 – $0.242 per share).

Net Asset Value

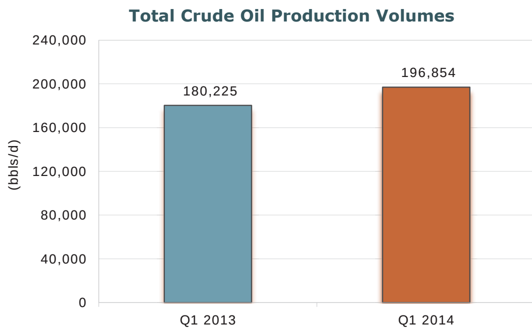
We measure our success in a number of ways with a key measure being growth in net asset value. We continue to believe that our goal of doubling our December 2009 net asset value by the end of 2015 is an achievable target.

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

The first quarter of 2014 continued to reflect the strength of our integrated approach. Upstream Operating Cash Flow increased 35 percent compared to 2013 due to higher crude oil blend and natural gas sales prices and rising crude oil production. Crude oil sales prices increased 35 percent mainly due to the narrowing of the West Texas Intermediate ("WTI") to Western Canadian Select ("WCS") differential by 28 percent and the weakening of the Canadian dollar. The WTI-WCS differential narrowed to an average of US$23.13 per barrel (2013 – US$31.96). The rise in WCS to US$75.55 per barrel (2013 – US$62.41 per barrel) increased the cost of our heavy crude oil feedstock which, along with sharp declines in market crack spreads, resulted in lower Operating Cash Flow from our refining operations.

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

Total crude oil production in the first quarter averaged 196,854 barrels per day, in line with our expectations and an increase of nine percent from 2013.



Crude oil production from our Oil Sands segment averaged 120,444 barrels per day, an increase of 20 percent, primarily driven by higher production at Christina Lake. Average production at Christina Lake was 65,738 barrels per day, a 48 percent increase, as phase D reached full production capacity in 2013 and phase E approached full production capacity in 2014. With the addition of phase E, our tenth oil sands expansion phase, nameplate capacity increased to 138,000 gross barrels per day.

Foster Creek production averaged 54,706 barrels per day, in line with our expectations.

Our Conventional crude oil production averaged 76,410 barrels per day. The sale of our Lower Shaunavon asset in July 2013 reduced production which offset the increased production at Pelican Lake. Pelican Lake production averaged 24,782 barrels per day, an increase of five percent, resulting from additional infill wells coming on-stream and an increased response from the polymer flood program.

Our refining operations processed an average of 400,000 gross barrels per day (2013 – 416,000 gross barrels per day) of crude oil, of which 195,000 gross barrels per day was heavy crude oil (2013 – 197,000 gross barrels per day). We produced 420,000 gross barrels per day of refined products (2013 – 439,000). Refined product output in the first quarter of 2014 was impacted by planned maintenance and turnarounds at both refineries. In the first quarter of 2013, there were no significant turnaround activities at Borger.

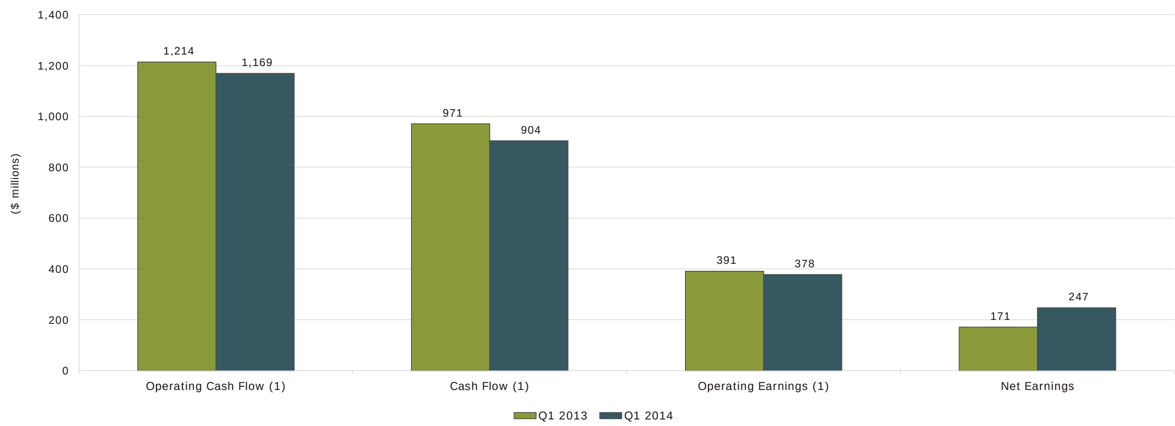
Other significant operational results in the first quarter of 2014 compared with 2013 include:

- Christina Lake reaching a cumulative production milestone of 100 million barrels of crude oil;
- Receiving regulatory approval for a 180,000 barrel per day commercial SAGD operation at our Grand Rapids project;
- Expanding our access to sales markets with approximately 7,117 barrels per day of crude oil transported by rail, including three unit train shipments, to the East Coast and the U.S.; and
- Entering into a purchase and sale agreement with an unrelated third party to sell certain of our Bakken properties. The sale was completed in April 2014 for proceeds of approximately $36 million before closing adjustments.

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

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.

Operating Cash Flow, Cash Flow, Operating Earnings and Net Earnings



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

In March 2014, we prepaid our Partnership Contribution Payable to WRB Refining LP in the amount of US$1.4 billion. To fund the prepayment, we used the net proceeds of US$1.4 billion received in December 2013 from our partner when they elected to prepay the Partnership Contribution Receivable. Other financial highlights for the first quarter of 2014 compared with 2013 include:

Revenues

Revenues of $5,012 million, increasing $693 million or 16 percent as a result of:

- Higher crude oil blend and natural gas sales prices, consistent with the increase in the WCS and AECO benchmark prices;
- Refining and Marketing revenues increasing $312 million primarily due to higher revenues from third-party sales of crude oil and natural gas. Increases were partially offset by a decrease in refining revenues due to lower refined product prices and declines in refined product output, partially offset by the weakening of the Canadian dollar; and
- An increase in blended crude oil sales volumes, consistent with higher production volumes.

These increases to revenues were partially offset by declines in natural gas production volumes.

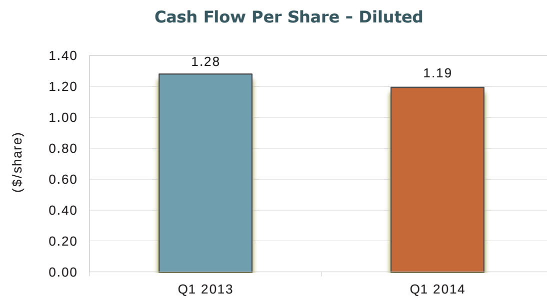
Operating Cash Flow

In the first quarter, Operating Cash Flow was $1,169 million, a decrease of $45 million. Upstream Operating Cash Flow increased $239 million, or 35 percent, to $924 million due to increasing crude oil and natural gas sales prices and higher crude oil production volumes at Christina Lake, partially offset by realized risk management losses compared to gains in 2013, a rise in operating costs, higher royalties and declines in natural gas production volumes. Operating costs increased primarily due to a rise in fuel costs, consistent with the increase in the AECO benchmark price. While higher natural gas prices increased our operating costs, overall the rise in natural gas pricing had a positive impact on Operating Cash Flow as we produced more natural gas than we used.

Increases in upstream Operating Cash Flow were partially offset by lower Operating Cash Flow from our Refining and Marketing segment, which decreased $284 million, or 54 percent, to $245 million primarily due to lower market crack spreads, higher heavy crude oil feedstock costs and decreased refined product output as a result of planned maintenance and turnarounds at both of our refineries. The Chicago and Midwest Combined 3-2-1 ("Group 3") market crack spreads decreased by approximately US$10 per barrel.

Cash Flow

Cash Flow decreased $67 million to $904 million, primarily due to changes discussed above in Operating Cash Flow and a decrease in interest income related to the early receipt of the Partnership Contribution Receivable in December 2013.



Operating Earnings

Operating Earnings decreased $13 million, or three percent, to $378 million. In addition to changes in Cash Flow discussed above, the decline was primarily due to a non-cash long-term incentive expense as compared to a recovery in 2013. Declines were partially offset by a decrease in deferred income tax expense and unrealized foreign exchange gains related to operating items compared to losses in 2013.

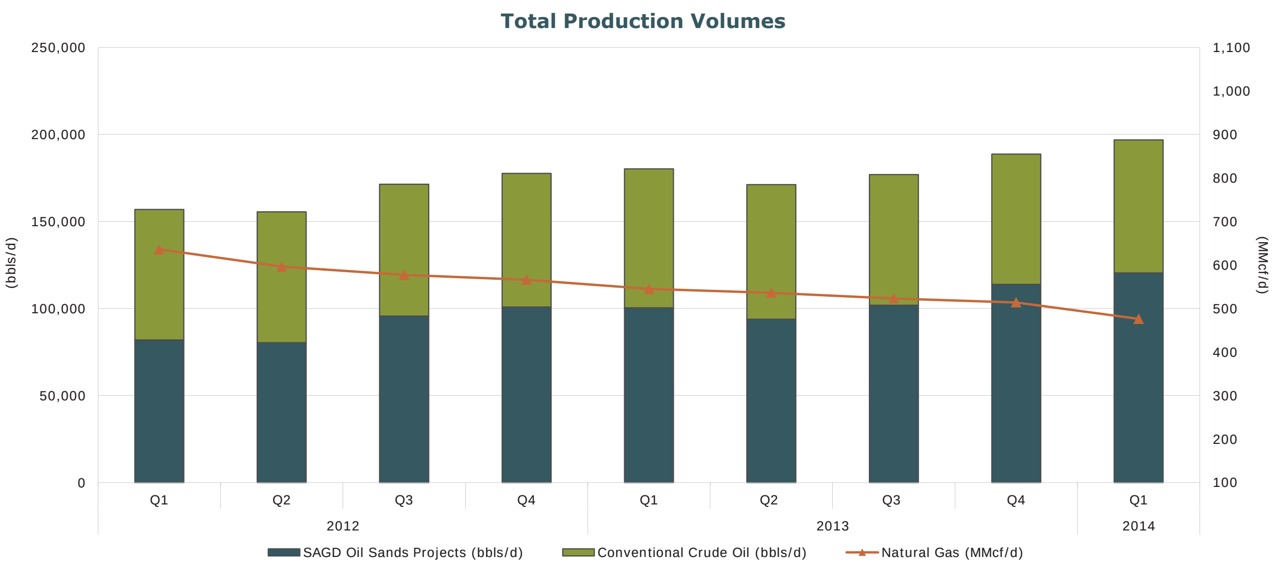
Net Earnings

Net Earnings increased $76 million, or 44 percent, to $247 million primarily due to unrealized risk management gains of $26 million compared with losses of $230 million in 2013. Increases were partially offset by an unrealized foreign exchange loss on long-term debt of $196 million compared with losses of $47 million related to long-term debt and the Partnership Contribution Receivable in 2013, and changes in Operating Earnings discussed above.

Capital Investment

Capital investment was $829 million, with most of our spend occurring at 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 March 31, 2014	Percent Change	2013
Oil Sands			
Foster Creek	**54,706**	**(2)%**	55,996
Christina Lake	**65,738**	**48%**	44,351
	120,444	**20%**	100,347
Conventional			
Pelican Lake	**24,782**	**5%**	23,687
Other Heavy Oil	**16,017**	**(4)%**	16,712
Total Heavy Oil	**40,799**	**1%**	40,399
Light & Medium Oil	**34,598**	**(10)%**	38,508
NGLs (1)	**1,013**	**4%**	971
Total Conventional	**76,410**	**(4)%**	79,878
Total Crude Oil Production	**196,854**	**9%**	180,225

(1) NGLs include condensate volumes.

In the first quarter, our crude oil production increased nine percent driven by higher production at Christina Lake as a result of phase D reaching full production capacity in 2013 and phase E approaching full production capacity in 2014. The ramp up of phase E, which started producing in July 2013, proceeded similar to the ramp up of phases C and D, approaching nameplate capacity within six to nine months of first production.

Foster Creek is operating as expected. We are on track with our plan to optimize steam placement and continue to closely monitor 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 crude oil production from the Conventional segment decreased primarily due to the divestiture of our Lower Shaunavon asset, which produced an average of 4,888 barrels per day in the first quarter of 2013. The decline was partially offset by higher Pelican Lake production with additional infill wells coming on-stream and an increased response from our polymer flood program.

See the Reportable Segments section of this MD&A for more detail.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended March 31, 2014	2013
Conventional	**457**	527
Oil Sands	**19**	18
	476	545

We continue to focus on high rate of return projects and directing capital investment to our crude oil properties.

Operating Netbacks

	Crude Oil (1) ($/bbl)		Natural Gas ($/Mcf)	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	**2014**	2013
Price (2)	**73.12**	54.10	**4.47**	3.25
Royalties	**5.74**	3.42	**0.06**	0.05
Transportation and Blending (2)	**2.59**	2.81	**0.11**	0.15
Operating Expenses	**17.96**	15.19	**1.26**	1.14
Production and Mineral Taxes	**0.42**	0.55	**(0.01)**	0.03
Netback Excluding Realized Risk Management	**46.41**	32.13	**3.05**	1.88
Realized Risk Management Gain (Loss)	**(2.00)**	2.62	**-**	0.39
Netback Including Realized Risk Management	**44.41**	34.75	**3.05**	2.27

(1) Includes NGLs.
(2) The crude 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 was $34.54 per barrel for the first quarter (2013 – $31.09 per barrel).

In the first quarter, our crude oil netback, excluding realized risk management gains and losses, increased $14.28 per barrel from 2013 primarily due to higher sales prices, partially offset by increased operating costs. The rise in sales prices is consistent with the narrowing of the WTI-WCS differential and the weakening of the Canadian dollar. The increase in operating costs was primarily related to the increase in natural gas price, consistent with the rise in the AECO benchmark price.

The impact of rising natural gas prices on our operating costs, which represented $1.38 per barrel of the $2.77 per barrel increase, was more than offset by the benefit received from higher prices through an increase in natural gas revenues. In total, natural gas revenues increased $48 million and operating expenses related to fuel increased $27 million.

Our natural gas netback, excluding realized risk management gains and losses, increased $1.17 per Mcf predominantly 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 March 31,		
	2014	Percent Change	2013
Crude Oil Runs (Mbbls/d)	**400**	**(4)%**	416
Heavy Crude Oil	**195**	**(1)%**	197
Refined Product (Mbbls/d)	**420**	**(4)%**	439
Crude Utilization (percent)	**87**	**(4)%**	91

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

In the first quarter of 2014, both of our refineries underwent planned maintenance and turnarounds resulting in a decline in crude oil runs, refined product output and crude utilization. In the first quarter of 2013, there were no significant turnaround activities at Borger.

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 and 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]

	Q1 2014	Q4 2013	Q1 2013
Crude Oil Prices (US$/bbl)			
Brent			
Average	**107.90**	109.35	112.65
End of Period	**107.76**	110.80	110.02
WTI			
Average	**98.68**	97.46	94.37
End of Period	**101.58**	98.42	97.23
Average Differential Brent-WTI	**9.22**	11.89	18.28
WCS [2]			
Average	**75.55**	65.26	62.41
End of Period	**80.71**	74.80	82.71
Average Differential WTI-WCS	**23.13**	32.20	31.96
Condensate (C5 @ Edmonton) Average	**102.64**	94.22	107.24
Average Differential WTI-Condensate (Premium)/Discount	**(3.96)**	3.24	(12.87)
Average Differential WCS-Condensate (Premium)/Discount	**(27.09)**	(28.96)	(44.83)
Average Refined Product Prices (US$/bbl)			
Chicago Regular Unleaded Gasoline (“RUL”)	**113.04**	103.52	118.01
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**125.83**	121.98	129.46
Refining 3-2-1 WTI Average Crack Spreads (US$/bbl)			
Chicago	**18.55**	12.29	27.53
Group 3	**17.41**	10.66	27.93
Natural Gas Average Prices			
AECO (C$/Mcf)	**4.76**	3.15	3.08
NYMEX (US$/Mcf)	**4.94**	3.60	3.34
Basis Differential NYMEX-AECO (US$/Mcf)	**0.60**	0.59	0.27
Foreign Exchange Rates (US$/C$1)			
Average	**0.906**	0.953	0.992

(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 first quarter of 2014 was C$83.39 (2013 – C$62.91).*

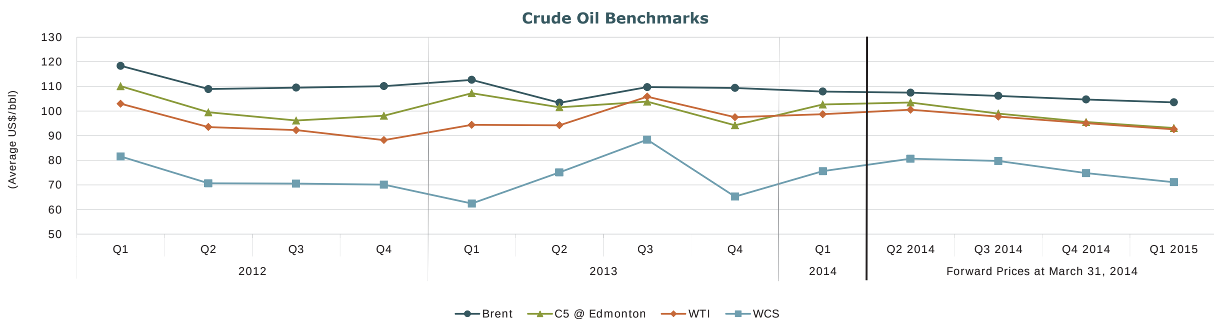
Crude Oil Benchmarks

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of changes in inland refined product prices. In the first quarter of 2014, the average price of Brent crude oil decreased by US$4.75 per barrel compared to the same period last year. Lower prices in the quarter resulted from declines in the U.S. economy from adverse weather conditions, economic uncertainty in China and the potential return of Iranian and Libyan production to the global market. The first quarter of 2013 experienced higher Brent crude oil pricing as a result of accelerating U.S. economic momentum and Iranian supply uncertainty.

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 narrowed significantly in the first quarter. New pipeline infrastructure from the Cushing, Oklahoma area to the U.S. Gulf Coast relieved congestion that developed in 2013 due to the rapid growth of U.S. inland supply, allowing U.S. Gulf Coast refineries access to WTI crude oil, reducing the discount applied to the WTI benchmark price.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WTI-WCS average differential narrowed by US$8.83 per barrel due to increased Canadian heavy crude oil volumes shipped by rail, allowing access to more Canadian and U.S. markets; and higher utilization of existing pipelines and new pipeline capacity, increasing U.S. refinery access to the growing crude oil production in Alberta.

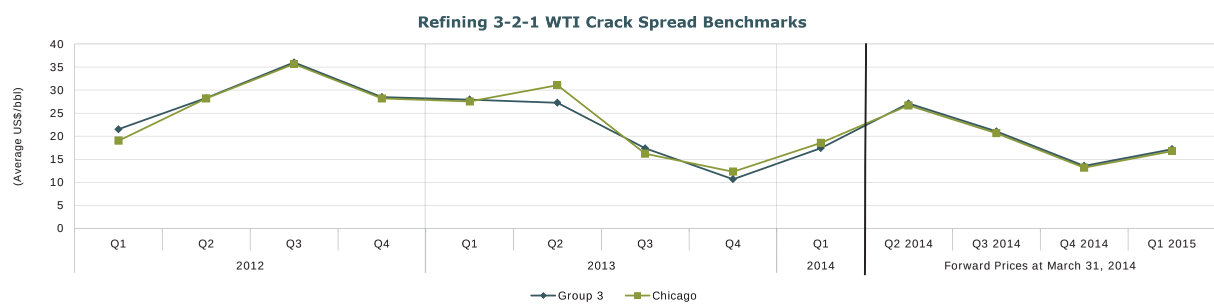
Blending condensate with bitumen and heavy oil enables our production to be transported. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential results in an increase in the recovery of condensate costs 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. Condensate prices decreased in the first quarter by US$4.60 per barrel compared to 2013 due to the same reasons discussed above that impacted the Brent benchmark price. The WCS-Condensate differential narrowed by US$17.74 per barrel in the first quarter compared to 2013 primarily due to the increase in the WCS benchmark price.



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 market crack spreads in the U.S. inland Chicago and Group 3 markets fell in the first quarter compared with 2013 primarily due to the strengthening of WTI prices as inland congestion issues were addressed, a reduction in refinery outages in 2014, and a decline in refined product prices.

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 based on a first in, first out accounting basis.



Other Benchmarks

Average natural gas prices increased significantly in the first quarter of 2014 compared to the same period last year due to an abnormally cold winter leading to large draws of natural gas from 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 first quarter of 2014 compared to the same period last year, the Canadian dollar weakened by $0.09, or nine percent, relative to the U.S. dollar due to narrowing U.S./Canadian interest differentials. U.S. interest rates rose while Canadian interest rates increased only slightly 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 the first quarter of 2014 as compared with 2013 increased our current period's revenues by US$431 million.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The following key performance indicators are discussed in more detail within this section.

($ millions, except per share amounts)	2014 Q1	2013 Q4	2013 Q3	2013 Q2	2013 Q1	2012 Q4	2012 Q3	2012 Q2	2012 Q1
Revenues	**5,012**	4,747	5,075	4,516	4,319	3,724	4,340	4,214	4,564
Operating Cash Flow (1) (2)	**1,169**	976	1,153	1,125	1,214	966	1,314	1,081	1,090
Cash Flow (1)	**904**	835	932	871	971	697	1,117	925	904
Per Share – Diluted	**1.19**	1.10	1.23	1.15	1.28	0.92	1.47	1.22	1.19
Operating Earnings (Loss) (1)	**378**	212	313	255	391	(188)	432	284	340
Per Share – Diluted	**0.50**	0.28	0.41	0.34	0.52	(0.25)	0.57	0.37	0.45
Net Earnings (Loss)	**247**	(58)	370	179	171	(117)	289	397	426
Per Share – Basic	**0.33**	(0.08)	0.49	0.24	0.23	(0.15)	0.38	0.53	0.56
Per Share – Diluted	**0.33**	(0.08)	0.49	0.24	0.23	(0.15)	0.38	0.52	0.56
Capital Investment (3)	**829**	898	743	706	915	978	830	660	900
Cash Dividends	**202**	183	182	183	184	167	166	166	166
Per Share	**0.2662**	0.242	0.242	0.242	0.242	0.22	0.22	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 first quarter, revenues increased $693 million or 16 percent compared with 2013.

($ millions)	
Revenues for the Three Months Ended March 31, 2013	**4,319**
Increase (Decrease) due to:	
Oil Sands	**371**
Conventional	**129**
Refining and Marketing	**312**
Corporate and Eliminations	**(119)**
Revenues for the Three Months Ended March 31, 2014	**5,012**

Upstream revenues increased 33 percent due to rising crude oil blend and natural gas sales prices, and higher blended crude oil sales volumes, partially offset by increased royalties and lower natural gas production.

Revenues generated by the Refining and Marketing segment increased 11 percent as revenues from third-party sales, undertaken to provide operational flexibility, increased as a result of a rise in crude oil and natural gas pricing and purchased volumes. Revenue from our refining operations declined due to lower refined product prices and decreases in refined product output, partially offset by the weakening of the Canadian dollar.

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

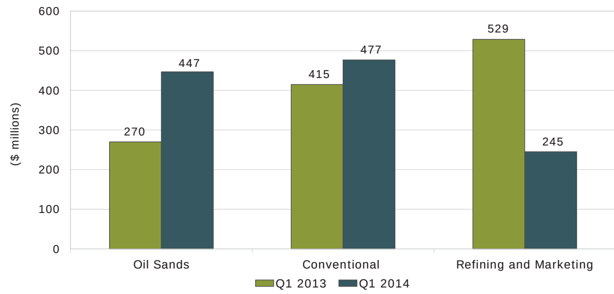
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

Operating Cash Flow

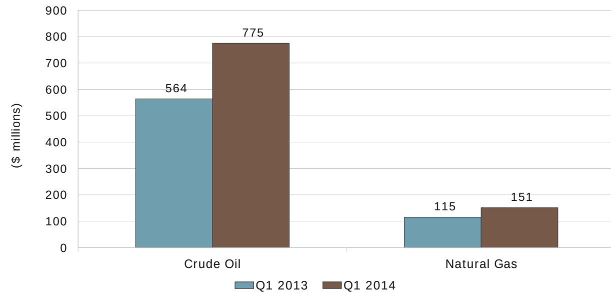
Operating Cash Flow is a non-GAAP measure that is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between years. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, 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.

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Revenues	**5,253**	4,441
(Add) Deduct:		
Purchased Product	**2,820**	2,277
Transportation and Blending	**653**	558
Operating Expenses	**574**	440
Production and Mineral Taxes	**7**	10
Realized (Gain) Loss on Risk Management Activities	**30**	(58)
Operating Cash Flow	**1,169**	1,214

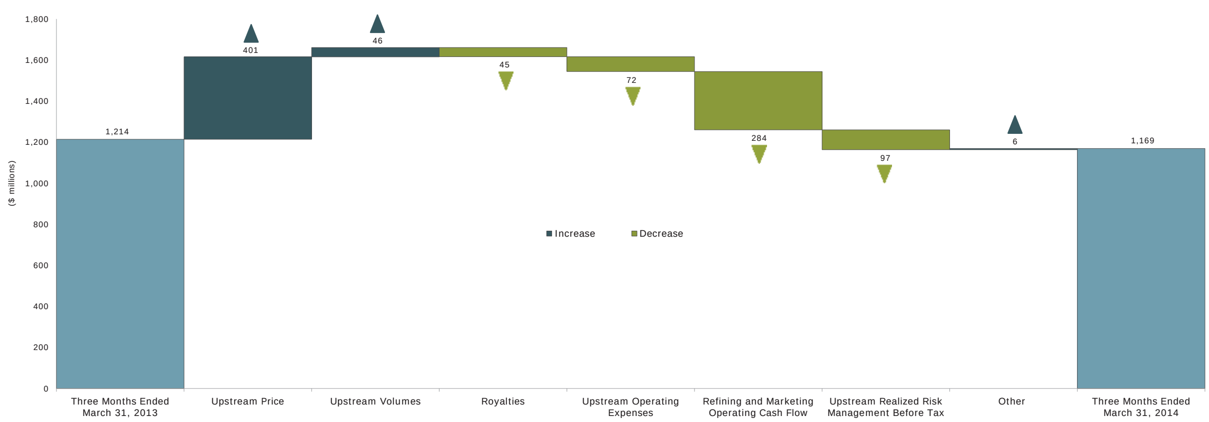
Operating Cash Flow by Segment



Upstream Operating Cash Flow by Product



Operating Cash Flow Variance for the Three Months Ended March 31, 2014 Compared With March 31, 2013



As highlighted in the above graph, our Operating Cash Flow decreased four percent primarily due to:

- A decline in Operating Cash Flow from Refining and Marketing of $284 million primarily due to a decline in market crack spreads, higher heavy crude oil feedstock costs and lower refined product output, consistent with planned maintenance and turnarounds at both of our refineries in the quarter;
- Realized risk management losses before tax, excluding Refining and Marketing, of $35 million compared with gains of $62 million in 2013; and
- An increase in crude oil operating expenses of $68 million, primarily due to a rise in fuel costs consistent with the increase in the AECO natural gas price. The impact of rising natural gas price on our operating expenses was offset by the increase in natural gas revenues, as we produced more natural gas than we used. On a per barrel basis, crude oil operating costs increased by $2.77 to $17.96 per barrel, with $1.38 per barrel of the increase related to the rise in natural gas prices.

The decreases were partially offset by:

- A 35 percent increase in our average crude oil sales price to $73.12 per barrel and a 38 percent increase in our average natural gas sales price to $4.47 per Mcf; and
- An increase in our crude oil sales volumes by seven percent.

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.

($ millions)	Three Months Ended March 31, 2014	2013
Cash From Operating Activities	**457**	895
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(42)**	(34)
Net Change in Non-Cash Working Capital	**(405)**	(42)
Cash Flow	**904**	971

In the first quarter of 2014, Cash Flow decreased $67 million due to the decline in Operating Cash Flow and a decrease of $25 million in interest income primarily due to the receipt of the Partnership Contribution Receivable in December 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.

($ millions)	Three Months Ended March 31, 2014	2013
Earnings, Before Income Tax	**358**	294
Add (Deduct):		
Unrealized Risk Management (Gain) Loss (1)	**(26)**	230
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**196**	47
Operating Earnings, Before Income Tax	**528**	571
Income Tax Expense	**150**	180
Operating Earnings	**378**	391

(1) The unrealized risk management (gains) losses include 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.

Including the changes discussed above in Cash Flow, Operating Earnings decreased $13 million in the first quarter primarily related to a non-cash long-term incentive expense compared to a recovery in 2013. Decreases were partially offset by:

- Unrealized foreign exchange gains related to operating items of $53 million compared to losses of $3 million in 2013; and
- A decrease in income tax of $30 million primarily as a result of lower U.S. deferred taxes.

Net Earnings

($ millions)	
Net Earnings for the Three Months Ended March 31, 2013	**171**
Increase (Decrease) due to:	
Operating Cash Flow (1)	**(45)**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**256**
Unrealized Foreign Exchange Gain (Loss)	**(93)**
Expenses (2)	**(55)**
Depreciation, Depletion and Amortization	**1**
Income Taxes	**12**
Net Earnings for the Three Months Ended March 31, 2014	**247**

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

Including the changes discussed above in the Cash Flow and Operating Earnings sections, our Net Earnings increased 44 percent in the first quarter primarily due to unrealized risk management gains of $26 million compared to losses of $230 million in 2013. Increases were partially offset by an unrealized foreign exchange loss on long-term debt of $196 million compared to losses of $47 million related to long-term debt and the Partnership Contribution Receivable in 2013 as a result of a weaker Canadian dollar.

Net Capital Investment

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Oil Sands	**527**	537
Conventional	**270**	338
Refining and Marketing	**23**	25
Corporate	**9**	15
Capital Investment	**829**	915
Acquisitions	**1**	3
Divestitures	**(2)**	(1)
Net Capital Investment (1)	**828**	917

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

Oil Sands capital investment in the first quarter focused primarily on the development of the expansion phases at Foster Creek and Christina Lake, and the construction of phase A at Narrows Lake. Capital investment includes the drilling of 279 gross stratigraphic test wells.

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 managed in response to the natural gas price environment.

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

Capital also includes spending on technology development, which plays an integral role in our business. Having an integrated innovation and technology development strategy 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:

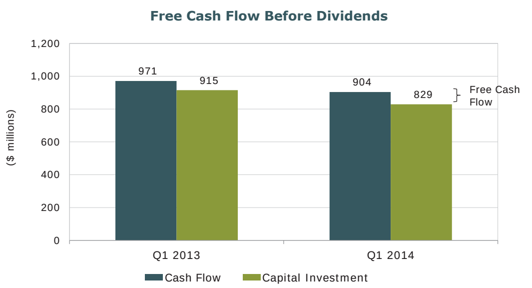
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a meaningful dividend as part of providing strong total shareholder return; and
- Third, 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 March 31,	
($ millions)	**2014**	2013
Cash Flow [(1)]	**904**	971
Capital Investment (Committed and Growth)	**829**	915
Free Cash Flow [(2)]	**75**	56
Dividends Paid	**202**	184
	(127)	(128)

(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.

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 March 31,	
($ millions)	**2014**	2013
Oil Sands	**1,209**	838
Conventional	**786**	657
Refining and Marketing	**3,258**	2,946
Corporate and Eliminations	**(241)**	(122)
	5,012	4,319

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 first quarter of 2014 compared with 2013 include:

- Christina Lake production increasing 48 percent, to an average of 65,738 barrels per day, primarily due to phase E approaching full production capacity in the first quarter of 2014;
- Foster Creek production averaging 54,706 barrels per day;
- Receiving regulatory approval for a 180,000 barrel per day commercial SAGD operation at our Grand Rapids project; and
- Successfully completing a winter stratigraphic test well program, drilling 279 gross wells.

Oil Sands – Crude Oil

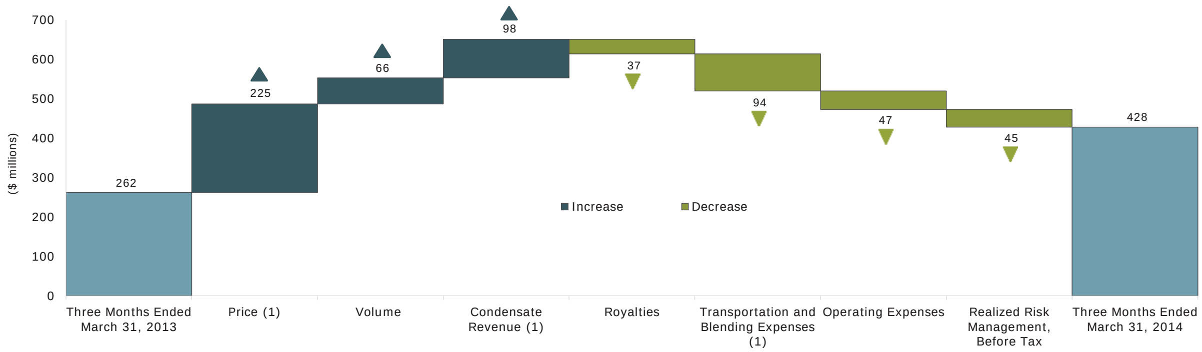
Financial Results

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Gross Sales	**1,230**	841
Less: Royalties	**51**	14
Revenues	**1,179**	827
Expenses		
Transportation and Blending	**559**	465
Operating	**170**	123
(Gain) Loss on Risk Management	**22**	(23)
Operating Cash Flow [(1)]	**428**	262
Capital Investment	**525**	536
Operating Cash Flow Net of Related Capital Investment	**(97)**	(274)

(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.

Operating Cash Flow Variance for the Three Months Ended March 31, 2014 Compared With March 31, 2013



(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 quarter, our average crude oil sales price was $65.19 per barrel, 48 percent higher than in 2013. This is consistent with the increase in the WCS benchmark price, the strengthening of the Christina Dilbit Blend ("CDB") price and the weakening of the Canadian dollar. The WCS-CDB differential narrowed by 35 percent, to a discount of US$4.90 per barrel (2013 – US$7.51 per barrel), primarily related to improved pipeline access to the U.S. Gulf Coast and the associated access to refineries that can process heavier crude oil. In the first quarter, 53,839 barrels per day of Christina Lake production was sold as CDB (2013 – 37,635 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

	Three Months Ended March 31,		
(barrels per day)	**2014**	**Percent Change**	2013
Foster Creek	**54,706**	**(2)%**	55,996
Christina Lake	**65,738**	**48%**	44,351
	120,444	**20%**	100,347

In line with our expectations, Foster Creek production averaged 54,706 barrels per day in the first quarter of 2014. We are on track with our plan to optimize steam placement and continue to monitor conditions in the reservoir as common steam chambers form in the initial project areas. We are using new operating techniques to improve the conformance of steam along wellbores. In addition, we continue to use our Wedge Well[TM] technology to capture production from areas between steam chambers. In the near-term, we expect to see a higher steam to oil ratio ("SOR") and production levels between 100,000 and 110,000 gross barrels per day. We remain confident in the overall magnitude of the resource. As we continue to learn more about operating a SAGD project with common steam chambers and build out the remaining phases, we will look to further optimize both the SOR and plant upgrades for the entire facility.

Christina Lake production increased as a result of phase D reaching full production capacity in 2013 and phase E approaching full production capacity in 2014.

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 oil sold and include the value of 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 in the first 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 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. Gross revenues are a function of sales volumes and realized prices.

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). Net profits are a function of sales volumes, realized prices and allowed operating and capital costs.

Royalties increased $37 million during the first quarter of 2014, primarily due to higher realized prices at both Foster Creek and Christina Lake. At Foster Creek this resulted in a royalty calculation based on net profits in the first quarter of 2014 as compared to a calculation based on gross revenues in 2013.

Effective Royalty Rates

	Three Months Ended March 31,	
(percent)	**2014**	2013
Foster Creek	**8.1**	2.9
Christina Lake	**7.1**	5.7

Expenses

Transportation and Blending

Transportation and blending costs rose $94 million or 20 percent. Blending costs rose due to higher production and an increase in the cost of condensate. Transportation charges were $4 million lower due to volumes shipped on the Trans Mountain pipeline system, resulting in lower transportation charges for our net share, and lower sales into the U.S. market which attract higher tariffs.

Operating

Primary drivers of our operating costs in the first quarter of 2014 were fuel costs, workforce and workover activities. In total, operating costs increased $47 million or $2.43 per barrel.

Per-unit Operating Costs

	Three Months Ended March 31,		
($/bbl)	**2014**	**Percent Change**	2013
Foster Creek			
Fuel	**5.45**	**87%**	2.91
Non-fuel	**13.64**	**23%**	11.12
Total	**19.09**	**36%**	14.03
Christina Lake			
Fuel	**4.83**	**31%**	3.69
Non-fuel	**8.47**	**(8)%**	9.24
Total	**13.30**	**3%**	12.93

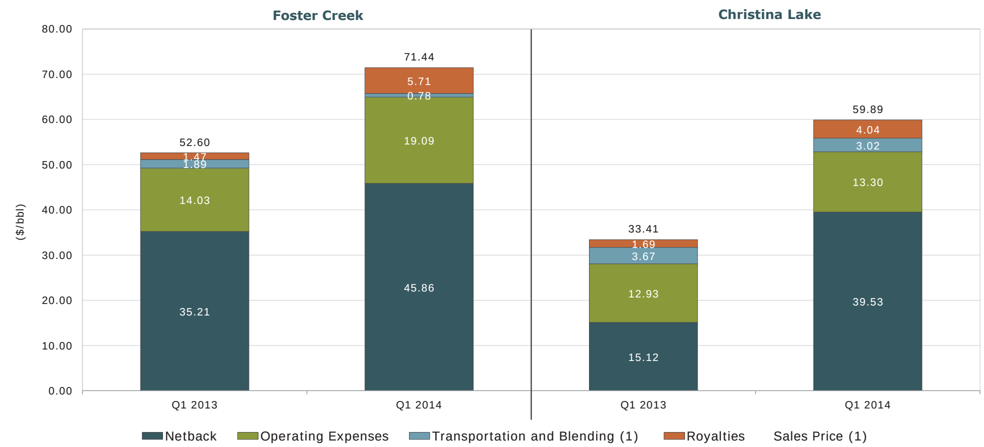
Foster Creek operating costs rose $5.06 per barrel, primarily due to an increase of $1.89 per barrel related to the rise in natural gas price. Overall, operating costs rose $23 million due to:

- Higher fuel costs, an increase of $12 million primarily related to the rise in natural gas price, consistent with the rising benchmark AECO price;
- Higher workforce costs as we hired additional field staff in advance of the start-up of the phase F expansion expected in the third quarter of 2014; and
- Increased workover activities related to well servicing.

Christina Lake operating costs increased $0.37 on a per barrel basis primarily due to an increase of $1.64 per barrel related to the rise in natural gas price. Per barrel non-fuel costs decreased primarily due to higher production volumes. Overall, operating costs rose $24 million due to:

- Higher fuel costs, an increase of $13 million, as a result of rising production and increased fuel prices consistent with the rising benchmark AECO natural gas price; and
- Increased workover activities related to well servicing.

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 first quarter was $48.35 per barrel (2013 – $46.00 per barrel) for Foster Creek; and $52.81 per barrel (2013 – $51.46 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

Risk Management

Risk management activities in the first quarter resulted in realized losses of $22 million (2013 – gains of $23 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, remained consistent at 19 MMcf per day in the first quarter compared to 2013 (2013 – 18 MMcf per day). Operating Cash Flow was $23 million in the first quarter (2013 – $4 million), increasing due to higher realized natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2014	2013
Foster Creek	**221**	210
Christina Lake	**182**	175
	403	385
Narrows Lake	**47**	25
Telephone Lake	**52**	53
Grand Rapids	**11**	18
Other (1)	**14**	56
Capital Investment (2)	**527**	537

(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 the first quarter focused on expansion of phases F, G and H, drilling of sustaining wells, and operational improvement projects. Spending also included the drilling of 145 gross stratigraphic test wells (2013 – 111 gross wells). Capital investment increased due to phase F well pad construction, wedge well drilling and an increase in stratigraphic test wells drilled.

In the first quarter, Christina Lake capital investment focused on expansion of phase F, phase E well pad and facility construction, and the drilling of sustaining wells. Capital investment also included the drilling of 51 gross stratigraphic test wells (2013 – 68 gross wells). Capital investment increased slightly due to higher spending on wedge well and sustaining well drilling, and phase F plant construction, partially offset by lower spending on phase E plant construction.

In the first quarter, capital investment increased at Narrows Lake as spending continued on phase A engineering, procurement and plant construction, which started in the third quarter of 2013. Capital investment also included the drilling of 22 gross stratigraphic test wells (2013 – 26 gross wells).

Emerging Projects

At Telephone Lake, our capital investment was primarily focused on front end engineering and costs related to the pilot project. In the first quarter, investment remained consistent to 2013 and included the drilling of 31 stratigraphic test wells (2013 – 28 wells).

Capital investment at Grand Rapids was primarily focused on costs related to the pilot project. Capital investment declined in the first quarter due to a reduction in spending on the pilot project, partially offset by drilling nine stratigraphic test wells in 2014 (2013 – one well). The purpose of the pilot is to test reservoir performance.

Drilling Activity

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

	Gross Stratigraphic Test Wells		Gross Production Wells (1) (2)	
	Three Months Ended March 31,			
	2014	2013	**2014**	2013
Foster Creek	**145**	111	**15**	1
Christina Lake	**51**	68	**18**	5
	196	179	**33**	6
Narrows Lake	**22**	26	**-**	-
Telephone Lake	**31**	28	**-**	-
Grand Rapids	**9**	1	**-**	-
Other	**21**	72	**-**	-
	279	306	**33**	6

(1) Includes wells drilled using our Wedge Well™ technology.
(2) SAGD well pairs are counted as a single producing well.
(3) In addition, we drilled one gross service well in the first quarter of 2014 (2013 – eight gross service wells).

Future Capital Investment

Foster Creek is currently producing from phases A through E. Expansion work is underway at phases F, G and H. Foster Creek capital investment for 2014 is forecast to be between $680 million and $760 million and is primarily focused on expansion phases, sustaining wells and operational improvement projects. Expansion work at phases F, G and H is proceeding as planned. We expect phases F, 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. Production from phase F is expected to start in the third quarter of 2014 with ramp-up to design capacity expected to take twelve to eighteen months. Production start-up from phases G and H is anticipated in 2015 and 2016, respectively. We submitted a joint application and EIA to regulators in February 2013 for an additional expansion, phase J, and we anticipate receiving regulatory approval in the first quarter of 2015.

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 $750 million and $820 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 wedge wells and sustaining wells. 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 fourth quarter of 2014.

For our Narrows Lake property, we received regulatory approval in May 2012 for phases A, B and C, 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 $210 million and $230 million in 2014 and is primarily focused on plant construction, procurement and offsite fabrication for phase A and infrastructure for a construction camp. The first phase of the project is anticipated to have a production capacity of 45,000 gross barrels per day, with first oil expected in 2017.

Two of our emerging projects are Telephone Lake and Grand Rapids. At our Telephone Lake project located within the Borealis region, we commenced a dewatering pilot in the fourth quarter of 2012 and we completed the pilot in October 2013. At our Grand Rapids project located within the Greater Pelican region, a SAGD pilot project is underway. We received regulatory approval in March 2014 for a 180,000 barrel per day commercial SAGD operation. We plan to continue operating the pilot project to gather additional information on the reservoir.

Additional capital investment of approximately $140 million to $160 million in 2014 is expected for our emerging SAGD projects and is primarily focused on drilling stratigraphic test wells, front end engineering at Telephone Lake and costs related to the pilot projects at Telephone Lake and Grand Rapids. At Telephone Lake we are advancing the regulatory application for the project and anticipate receiving approval in the second half 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 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 first quarter, Oil Sands DD&A increased $38 million to $143 million (2013 – $105 million) due to increased DD&A rates for both of our properties due to increased expenditures, a rise in future development costs associated with total proved reserves and higher sales volumes.

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. 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 our future growth opportunities in our Oil Sands segment.

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

- Crude oil production averaging 76,410 barrels per day, decreasing four percent primarily due to the sale of our Lower Shaunavon asset and expected natural declines, partially offset by successful horizontal well performance in southern Alberta associated with our current drilling program and higher production at Pelican Lake; and
- Generating Operating Cash Flow net of capital investment of $207 million, an increase of $130 million.

In March, we entered into a purchase and sale agreement with an unrelated third party, to sell certain of our Bakken properties in southeastern Saskatchewan. The sale was completed in April 2014 for proceeds of $36 million before closing adjustments. A gain on disposition of approximately $17 million is expected to be recorded in the second quarter of 2014. The associated property, plant and equipment and decommissioning liabilities of $28 million and $10 million, respectively, were reclassified at March 31, 2014 as assets and liabilities held for sale. During the first quarter, these Bakken properties had crude oil production averaging 396 barrels per day (2013 – 773 barrels per day).

In the first quarter of 2013, we entered into a purchase and sale agreement with an unrelated third party to sell our Lower Shaunavon asset. The sale was completed in July 2013 for proceeds of approximately $240 million plus closing adjustments. Lower Shaunavon produced an average of 4,888 barrels per day in the first quarter of 2013.

Conventional – Crude Oil

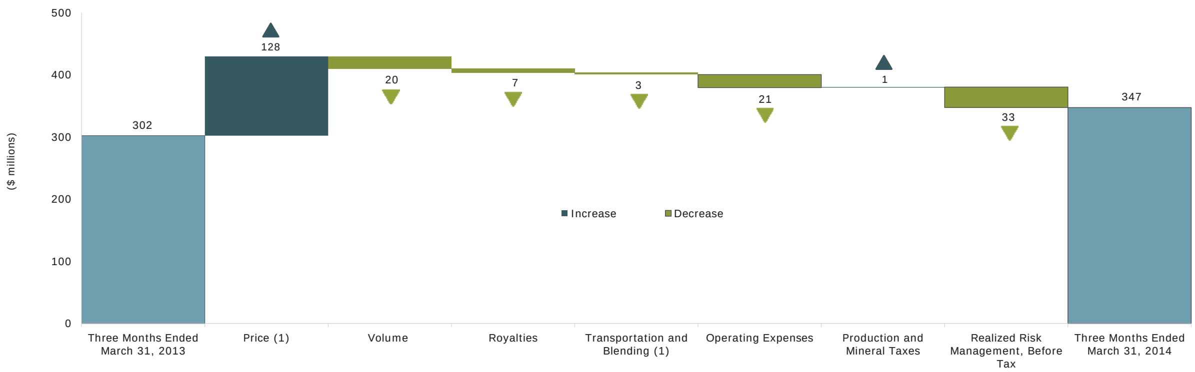
Financial Results

($ millions)	Three Months Ended March 31, 2014	2013
Gross Sales	**651**	543
Less: Royalties	**49**	42
Revenues	**602**	501
Expenses		
Transportation and Blending	**89**	86
Operating	**145**	124
Production and Mineral Taxes	**8**	9
(Gain) Loss on Risk Management	**13**	(20)
Operating Cash Flow [1]	**347**	302
Capital Investment	**263**	330
Operating Cash Flow Net of Related Capital Investment	**84**	(28)

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

Capital investment in excess of Operating Cash Flow in 2013 was funded through Operating Cash Flow generated by natural gas sales in our Conventional segment and from our Refining and Marketing segment.

Operating Cash Flow Variance for the Three Months Ended March 31, 2014 Compared With March 31, 2013



(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 increased 28 percent to $85.38 per barrel, consistent with the change in crude oil benchmark prices and associated differentials.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2014	Percent Change	2013
Pelican Lake	**24,782**	**5%**	23,687
Other Heavy Oil	**16,017**	**(4)%**	16,712
Total Heavy Oil	**40,799**	**1%**	40,399
Light and Medium Oil	**34,598**	**(10)%**	38,508
NGLs	**1,013**	**4%**	971
	76,410	**(4)%**	79,878

Our crude oil production decreased four percent primarily due to the sale of our Lower Shaunavon asset in July 2013 and expected natural declines, partially offset by successful horizontal well performance in southern Alberta associated with our current drilling program and higher production at Pelican Lake as a result of additional infill wells coming on-stream and an increased response from the polymer flood program. In the first quarter of 2013, Lower Shaunavon produced an average of 4,888 barrels per day.

Condensate

Revenues represent the total value of blended oil sold and include the value of condensate. The total value of condensate remained consistent in the first quarter as compared to 2013.

Royalties

Royalties increased $7 million primarily due to a rise in realized prices and an increase in sales volumes at Pelican Lake, partially offset by lower sales volumes at our other conventional properties.

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 the first quarter of 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 land, which is the land we hold the mineral rights to. Production from fee lands results in mineral tax recorded within production and mineral taxes.

In the first quarter, the effective crude oil royalty rate for all of our Conventional properties was 9.1 percent (2013 – 9.2 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $3 million in the first quarter of 2014. Transportation costs rose $3 million largely due to the higher cost associated with transporting our light and medium crude oil production by rail. The higher transportation cost for rail was more than offset by higher prices which overall improved our netback. The overall cost of condensate was unchanged as discussed in the Revenues section.

Operating

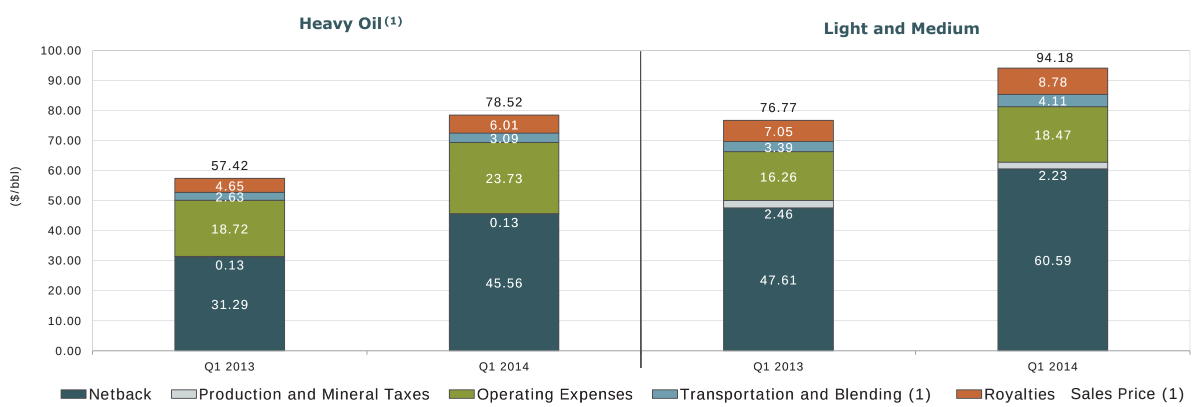
Primary drivers of our operating costs in the first quarter of 2014 were workover activities, workforce costs, electricity, repairs and maintenance and chemical consumption.

Operating costs for our Conventional crude oil properties increased $3.76 per barrel to $21.06 per barrel. The total dollar increase of $21 million was primarily due to:

- Increased workover and repairs and maintenance activities related to well optimizations; and
- Higher chemical costs associated with polymer consumption and price related to the expansion of the polymer flood program at Pelican Lake.

The cost increases in our crude oil operating costs were partially offset by declines in operating costs due to the sale of Lower Shaunavon.

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 our heavy oil properties was $17.56 per barrel in the first quarter (2013 – $17.93 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

Risk Management

Risk management activities in the first quarter resulted in realized losses of $13 million (2013 – gains of $20 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended March 31, 2014	2013
Gross Sales	**184**	155
Less: Royalties	**3**	2
Revenues	**181**	153
Expenses		
Transportation and Blending	**5**	7
Operating	**49**	52
Production and Mineral Taxes	**(1)**	1
(Gain) Loss on Risk Management	**-**	(18)
Operating Cash Flow (1)	**128**	111
Capital Investment	**7**	8
Operating Cash Flow Net of Related Capital Investment	**121**	103

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

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

Revenues

Pricing

Our average natural gas sales price increased $1.21 per Mcf to $4.46 per Mcf, consistent with the rise in the benchmark AECO natural gas price.

Production

Production decreased 13 percent to 457 MMcf per day primarily due to expected natural declines and temporary production losses due to wellhead freeze-offs as a result of cold weather.

Royalties

Royalties increased slightly as a result of higher prices, despite declines in production. The average royalty rate in the first quarter was 1.3 percent (2013 – 1.6 percent). Most of our natural gas production is located on fee land which results in mineral tax recorded within production and mineral taxes.

Expenses

Operating

Primary drivers of our operating expenses in the first quarter of 2014 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses decreased $3 million in the first quarter primarily related to a decrease in workforce costs due to strategic redeployment of workforce away from natural gas activities to focus on crude oil activities.

Risk Management

In the first quarter of 2014, there were no realized gains or losses on our natural gas contracts. Risk management activities in the first quarter of 2013 resulted in realized gains of $18 million, consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment (1)

($ millions)	Three Months Ended March 31, 2014	2013
Pelican Lake	**71**	140
Other Heavy Oil	**35**	32
Light and Medium Oil	**157**	158
Natural Gas	**7**	8
	270	338

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

Capital investment in the first quarter of 2014 was composed primarily of spending on tight oil development, facilities work, and on infill drilling, maintenance capital and facilities upgrades at Pelican Lake 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 initial results of the polymer flood program.

Conventional Drilling Activity

(net wells, unless otherwise stated)	Three Months Ended March 31, 2014	2013
Crude Oil	**52**	78
Recompletions	**223**	293
Gross Stratigraphic Test Wells	**13**	9
Other [1]	**16**	26

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

Crude oil wells drilled reflect the continued development of our Conventional properties. Well recompletions are mostly related to lower-risk Alberta coal bed methane development. Drilling of stratigraphic test wells increased in the first quarter of 2014 in order to further assess our tight oil plays in Alberta.

Future Capital Investment

In 2014, Pelican Lake capital investment is forecast to be between $230 million and $250 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 is forecast to be between $540 million and $590 million, which will be focused on tight oil development and facilities work.

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. 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.

In the first quarter, Conventional DD&A decreased $47 million to $252 million (2013 – $299 million) as a result of a decrease in the average DD&A rates and declines in sales volumes, due primarily to the sale of the Lower Shaunavon asset in July 2013.

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 related to our Refining and Marketing segment in the first quarter of 2014 compared with 2013 include:

- Refined product output declined as a result of planned maintenance and turnarounds at both refineries in 2014 as compared to 2013;
- Sanctioning a debottlenecking project at the Wood River Refinery; and
- Operating Cash Flow decreasing 54 percent to $245 million primarily due to declines in market crack spreads, higher heavy crude oil feedstock costs, and lower refined product output.

Refinery Operations [1]

	Three Months Ended March 31, 2014	2013
Crude Oil Capacity [2] (Mbbls/d)	**460**	457
Crude Oil Runs (Mbbls/d)	**400**	416
Heavy Crude Oil	**195**	197
Light/Medium	**205**	219
Crude Utilization (percent)	**87**	91
Refined Products (Mbbls/d)	**420**	439
Gasoline	**215**	225
Distillate	**130**	133
Other	**75**	81

(1) *Represents 100 percent of the Wood River and Borger refinery operations.*
(2) *The official nameplate capacity 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 first quarter of 2014, crude oil runs and refined product output declined due to planned maintenance and turnarounds at both of our refineries. In the first quarter of 2013, there were no significant turnaround activities at Borger. While total refined product output was decreased, the proportion of gasoline, distillate and other refined product output remained relatively the same.

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 heavy crude oil, a feedstock cost advantage is created by processing less expensive heavy 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.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Revenues	**3,258**	2,946
Purchased Product	**2,820**	2,277
Gross Margin	**438**	669
Expenses		
Operating [1]	**198**	136
(Gain) Loss on Risk Management	**(5)**	4
Operating Cash Flow [2]	**245**	529
Capital Investment	**23**	25
Operating Cash Flow Net of Related Capital Investment	**222**	504

(1) In 2013, we reclassified expenditures related to research activities from operating expenses to research costs.
(2) Non-GAAP measure defined in this MD&A.

Gross Margin

In the first quarter of 2014, the gross margin for the Refining and Marketing segment declined $231 million or 35 percent as a result of the 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 a decrease in refined product output, as a result of planned maintenance and turnarounds at both of our refineries in 2014.

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 first quarter of 2014, our RINs cost was $26 million relatively consistent with 2013 (2013 – $24 million). These costs remain a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating costs in the first quarter of 2014 were maintenance, labour, utilities and supplies. Operating costs increased 46 percent in 2014 primarily due to higher utility costs, resulting from a rise in natural gas and electricity prices, and increased costs associated with planned maintenance and turnaround activities in the quarter.

Refining and Marketing – Capital Investment

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Wood River Refinery	**11**	13
Borger Refinery	**12**	12
	23	25

Capital expenditures in the first quarter of 2014 focused on capital maintenance and refinery reliability and safety projects. We sanctioned a debottlenecking project at the Wood River Refinery in the first quarter of 2014. We are currently awaiting permit approval, which is expected in the fourth quarter of 2014, and planned start-up of the project is expected in the first quarter of 2016.

In 2014, we expect to invest between $150 million and $160 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. In the first quarter, Refining and Marketing DD&A increased $7 million to $39 million (2013 – $32 million) primarily due to the change in the US$/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 first quarter, our risk management activities resulted in $26 million of unrealized gains, before tax (2013 – $230 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.

	Three Months Ended March 31,	
($ millions)	**2014**	2013
General and Administrative	**109**	83
Finance Costs	**130**	123
Interest Income	**(2)**	(27)
Foreign Exchange (Gain) Loss, Net	**147**	52
Research Costs	**2**	3
Other (Income) Loss, Net	**(1)**	2
	385	236

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in the first quarter of 2014 were workforce, office rent and long-term incentive costs. General and administrative expenses increased $26 million primarily due to increases in long-term incentive expense, consistent with the change in our common share price, 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 were $7 million higher than in 2013 due to higher interest expenses on long-term debt resulting from the weakening of the Canadian dollar and higher unwinding of the discount on decommissioning liabilities. Increases were partially offset by lower interest incurred on the Partnership Contribution Payable as the balance continued to be repaid. On March 28, 2014, we exercised our right to prepay the remaining principal and accrued interest due under the Partnership Contribution Payable in the amount of US$1.4 billion, net to Cenovus. In order to fund this prepayment, we used the net proceeds of approximately US$1.4 billion received in December 2013 from our partner when they elected to prepay the Partnership Contribution Receivable.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the first quarter was 5.1 percent (2013 – 5.3 percent).

Foreign Exchange

	Three Months Ended March 31,	
($ millions)	**2014**	2013
Unrealized Foreign Exchange (Gain) Loss	**143**	50
Realized Foreign Exchange (Gain) Loss	**4**	2
	147	52

In the first quarter of 2014, the majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt with the weakening of the Canadian dollar at March 31, 2014.

DD&A

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.

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. DD&A for the first quarter was $20 million (2013 – $19 million) remaining relatively consistent.

Income Tax Expense

($ millions)	Three Months Ended March 31, 2014	2013
Current Tax		
Canada	**43**	30
U.S.	**32**	54
Total Current Tax	**75**	84
Deferred Tax	**36**	39
	111	123
Effective Tax Rate	**31%**	42%

The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation. 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.

In the first quarter of 2014, current taxes decreased $9 million compared with 2013 primarily due to a shift in the mix of where income is derived. Deferred tax decreased $3 million when compared to 2013. A decrease in the reversal of U.S. timing differences in the current quarter was offset by Canadian source unrealized risk management gains compared with losses in 2013. Given expected levels of income in the U.S. in 2014, the residual pool of U.S. net operating losses is expected to be fully claimed in 2014.

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 decrease in our effective tax rate in the first quarter when compared with 2013 is primarily due to lower levels of U.S. source income in 2014.

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.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended March 31, 2014	2013
Net Cash From (Used In)		
Operating Activities	**457**	895
Investing Activities	**(2,397)**	(903)
Net Cash Provided (Used) Before Financing Activities	**(1,940)**	(8)
Financing Activities	**246**	(166)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**57**	(8)
Increase (Decrease) in Cash and Cash Equivalents	**(1,637)**	(182)

	March 31, 2014	December 31, 2013
Cash and Cash Equivalents	**815**	2,452

At March 31, 2014, cash and cash equivalents of $815 million included $692 million of cash in FCCL Partnership and WRB Refining LP.

Operating Activities

Cash from operating activities was $438 million lower in the first quarter of 2014 mainly due to the change in non-cash working capital primarily due to increases in inventory related to downtime at our refinery in the quarter and to meet line fill requirements on new pipeline commitments. Excluding risk management assets and liabilities and assets and liabilities held for sale, working capital was $724 million at March 31, 2014 compared with $1,957 million at December 31, 2013. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In the first quarter, cash used in investing activities was $2,397 million, $1,494 million higher than in 2013. The increase was predominately due to the prepayment of the US$1.4 billion Partnership Contribution Payable in March 2014. In order to fund this prepayment, we used the net proceeds of approximately US$1.4 billion received in December 2013 from our partner when they elected to prepay the Partnership Contribution Receivable. The early repayment of the Partnership Contribution Payable will result in savings on interest costs that would have been paid over the next three years.

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. On March 31, 2014, we paid a dividend of $0.2662 per share (2013 – $0.242 per share). The total dividend payment in the first quarter was $202 million (2013 – $184 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Cash provided in financing activities in the first quarter increased $412 million from 2013 primarily as a result of an increase in short-term borrowings.

Our long-term debt at March 31, 2014, was $5,196 million with no principal payments due until October 2019 (US$1.3 billion). The $199 million increase in long-term debt from December 31, 2013 was due to fluctuations in foreign exchange rates.

As at March 31, 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 March 31, 2014.

($ millions)	Amount	Term
Cash and Cash Equivalents	**815**	**Not applicable**
Committed Credit Facility	**2,561**	**November 2017**
Canadian Base Shelf Prospectus (1)	**1,500**	**June 2014**
U.S. Base Shelf Prospectus (1)	**US$1,200**	**July 2014**

(1) Availability is 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 capacity under our committed credit facility for amounts of outstanding commercial paper.

As of March 31, 2014, no medium-term notes were issued under our Canadian shelf prospectus and US$1.2 billion remains available under our US$3.25 billion U.S. base shelf prospectus, the availability of which is dependent on market conditions.

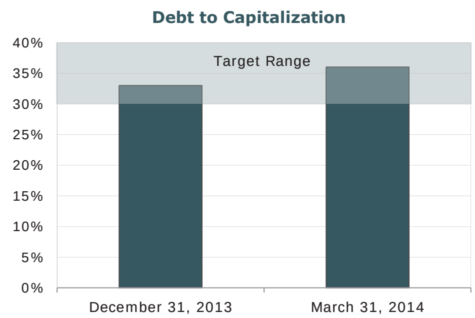
It is our intention to file a new Canadian shelf prospectus and a new U.S. shelf prospectus prior to the maturity of the existing prospectuses.

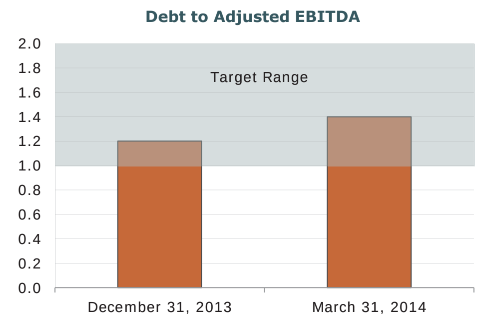
Financial Metrics

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. These metrics are used to steward our overall debt position and as measures of our overall financial strength.

As at	March 31, 2014	December 31, 2013
Debt to Capitalization	**36%**	33%
Debt to Adjusted EBITDA (times)	**1.4x**	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 March 31, 2014, our Debt to Capitalization and Debt to Adjusted EBITDA metrics were near the middle of our target ranges. The increase in our metrics can be attributed, in part, to higher long-term debt as a result of a weaker Canadian dollar and an increase in our short-term borrowings. 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. At March 31, 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 March 31, 2014	Units (thousands)
Common Shares	**756,868**
Stock Options	
NSRs	**41,299**
TSARs	**4,571**
Cenovus Replacement TSARs	**10**
Encana Replacement TSARs	**64**
Other Stock-Based Compensation Plans	
PSUs	**7,094**
DSUs	**1,263**

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.

We anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, 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.

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. 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 March 31,					
	2014			2013		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	34	(26)	8	(43)	190	147
Natural Gas	-	1	1	(19)	42	23
Refining	(4)	(1)	(5)	4	(2)	2
Power	-	-	-	-	-	-
(Gain) Loss on Risk Management	30	(26)	4	(58)	230	172
Income Tax Expense (Recovery)	(7)	7	-	14	(57)	(43)
(Gain) Loss on Risk Management, After Tax	23	(19)	4	(44)	173	129

In the first quarter of 2014, management of commodity price risk resulted in realized losses on crude oil financial instruments, consistent with average benchmark prices exceeding our contract prices. We recognized unrealized gains as a result of the changes in forward commodity prices compared with prices at the end of 2013 and changes in prices for transactions executed during the three months ended March 31, 2014, as well as the realization of settled positions, partially offset by 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 Judgments in Applying Accounting Policies

Critical 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 quarter 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 quarter 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 IAS 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

There were no new or amended standards issued during the three months ended March 31, 2014 that are applicable to Cenovus in future periods. A description of standards and interpretations that will be adopted by Cenovus 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") during the three months ended March 31, 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 strategy 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 are available on our website at cenovus.com.

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

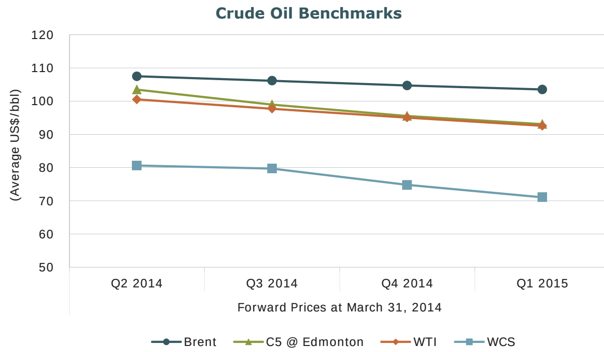
We continue to move forward on our business plan targeting net crude oil production, including our conventional oil operations, of more than 500,000 barrels per day. To achieve our development plans, additional expansions are planned at Foster Creek, Christina Lake and Narrows Lake, as well as new projects 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.

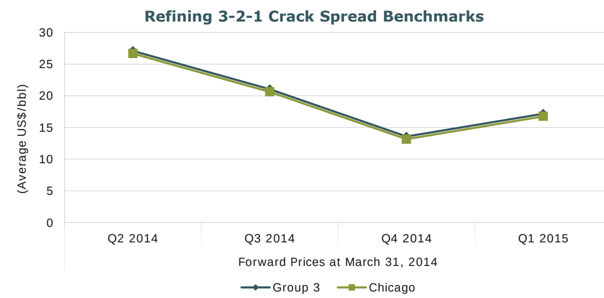
The following outlook commentary herein is focused on the next twelve months.

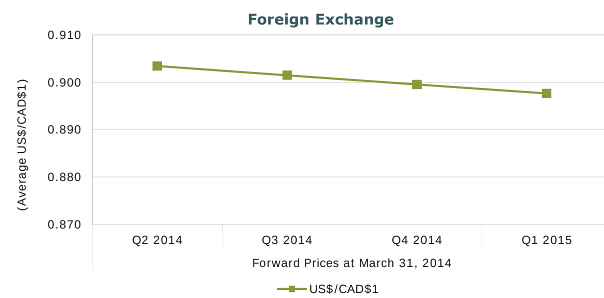
Commodity Prices Underlying our Financial Results

Our 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 and production interruptions. Economic indicators suggest an improvement in demand growth from the U.S. as the adverse weather impacts experienced in the first quarter of 2014 dissipate. North American supply growth is expected to continue at a strong, but moderating pace. Global supply disruptions are difficult to predict and materially impact the price of Brent crude oil. The impact of returning Iranian production could be offset by the Russian involvement in Crimea. The overall expectation is for a modest decline in Brent crude oil prices in 2014 compared with 2013, with higher valuations anticipated in the second half of 2014;
- The Brent-WTI differential is expected to narrow from 2013 as new pipeline capacity from Cushing to the Gulf Coast reduces inland congestion, partially offset by increased discounts of Gulf Coast crude oil prices relative to Brent crude oil prices as growing tight oil supply reduces the need for imports and creates occasional congestion;
- We expect 2014 WTI-WCS price differentials to narrow compared to 2013 levels with increased crude oil transport by rail and pipeline takeaway capacity more than offsetting crude supply growth;
- Average refining crack spreads in 2014 are expected to weaken compared with 2013, mostly due to a narrower Brent-WTI differential;
- Natural gas prices are expected to strengthen compared with 2013 due to reduced storage levels as a result of an abnormally cold winter; and
- An average foreign exchange forward price of US$0.901/C$1 over the next four quarters. The weakening of the Canadian dollar has a positive impact on our revenues and Operating Cash Flow.



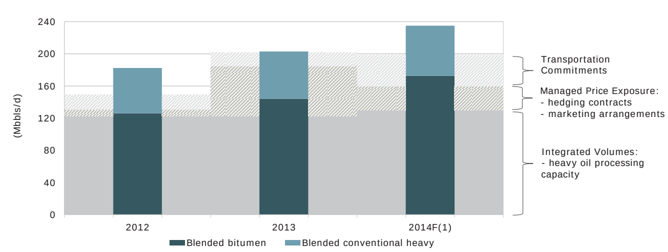




While we expect to see volatility in crude prices, we mitigate our exposure to light/heavy price differentials through the following:

- 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 prices from downside risk by entering into financial transactions that fix the WTI-WCS differential;
- 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 U.S. markets and also to 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 anticipate increasing our rail shipping capacity for crude oil to approximately 30,000 barrels per day by the end of 2014, subject to favourable market conditions, by supporting industry transportation projects as well as new and expanded market development initiatives for our crude oil.

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 Annual Information Form 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”, “intention”, “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 is based on an average diluted number of shares outstanding of approximately 757 million. It assumes: Brent US$105.00/bbl, WTI of US$102.00/bbl; Western Canada Select of US$76.00/bbl; NYMEX of US$4.00/MMBtu; AECO of $3.30/GJ; Chicago 3-2-1 crack spread of US$13.50/bbl; exchange rate of $0.98 US$/C$. For the period 2015 to 2023, assumptions include: Brent US$105.00-US$110.00; WTI of US$100.00-US$106.00/bbl; Western Canada Select of C$81.00-C$91.00/bbl; NYMEX of US$4.25-US$4.75/MMBtu; AECO of C$3.70-C$4.31/GJ; Chicago 3-2-1 crack spread of US$12.00-US$13.00; 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; 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.