MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED MARCH 31, 2015

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 28, 2015, should be read in conjunction with our March 31, 2015 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2014 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2014 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 28, 2015, 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 sedar.com, EDGAR at 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 listed on the Toronto and New York stock exchanges. On March 31, 2015, we had a market capitalization of approximately $18 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, 2015 was approximately 218,000 barrels per day and our average natural gas production was 462 MMcf per day. Our refineries processed an average of 439,000 gross barrels per day of crude oil feedstock into an average of 469,000 gross barrels per day of refined products.

The latter part of 2014 and the first quarter of 2015 have been very challenging for the oil and gas industry. The approximate 55 percent decline in crude oil prices since June 2014 has resulted in widespread reductions in capital spending programs and extensive efforts to reduce costs across the industry. Like all of our peers, Cenovus's share price has fallen, causing our market capitalization to drop approximately $8 billion since June 30, 2014. We are confident that commodity prices will eventually improve; however, the timing of that improvement is uncertain and we expect crude oil price and cash flow volatility in the near term. In the meantime, we are focused on preserving our financial resilience, exercising capital restraint and identifying sustainable cost reductions.

Our Strategy

Our strategy is to create value by developing our vast oil sands resources and by achieving stronger global prices for our products. It is based on our execution excellence, our ability to innovate and our financial strength. The manufacturing approach we use to produce oil is a key factor in how we execute our strategy. Applying standardized and repeatable designs and processes to the construction and operation of our facilities provides us with opportunities to reduce costs, and improve productivity and efficiencies at every phase of our oil sands projects. We are focused on driving total shareholder returns through share price appreciation and a strong and sustainable dividend.

Our integrated approach enables us to capture the full value chain from production to high-quality end products like transportation fuels. It relies on:

- Our producing asset mix, including:
  - Oil sands for growth;
  - Conventional crude oil for near-term cash flow and diversification of our revenue stream; and
  - 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.
- Our marketing, products and transportation activities, including:
  - Refining oil into various products to reduce the impact of commodity price fluctuations;
  - Creating a variety of oil blends to help maximize our transportation and refining options; and
  - Accessing new markets that will enable us to achieve the best pricing for our oil.

Oil Development

We are focusing on the development of our substantial crude oil resources, predominantly from Foster Creek and Christina Lake. Our future opportunities are currently based on the development of the land positions that we hold in the oil sands in northern Alberta, including Narrows Lake, Telephone Lake and Grand Rapids, as well as our conventional oil opportunities. Our normal development planning is to evaluate these resources through stratigraphic test well drilling programs.

We anticipate increasing our annual net crude oil production, including our conventional crude oil operations, to more than 500,000 barrels per day by fully developing our producing projects and those that currently have regulatory approval.

Execution Excellence

We apply a manufacturing-like, phased approach to developing our oil sands assets. This approach incorporates learnings from previous phases into future growth plans, allowing us to minimize costs. We continue to focus on executing our business plan in a safe, predictable and reliable way, leveraging the strong foundation we have built to date. We are committed to developing our resources safely and responsibly.

Financial Strength

We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. This is a significant reduction from 2014 levels in response to the continued low commodity price environment. A portion of our capital investment is expected to be internally funded through cash flow generated from our crude oil, natural gas and refining operations and the proceeds from our common share issuance in March 2015. We remain well positioned to manage through these volatile times. To continue to help ensure our financial flexibility, we will prudently use our balance sheet capacity, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

The declaration of dividends is at the sole discretion of our Board and is considered each quarter. In the first quarter, we paid a dividend of $0.2662 per share or $222 million, of which $138 million was paid in cash (2014 – $0.2662 per share or $202 million paid in cash). In February 2015, we initiated a three percent discount under our dividend reinvestment plan ("DRIP") for shareholders who reinvested their dividends in common shares.

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment continue to play 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, building on our history of excellent project execution. Environmental considerations are embedded into our business approach with the objective of reducing our environmental impact.

Our Operations

Oil Sands

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

	Three Months Ended March 31, 2015		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	50	67,901	135,802
Christina Lake	50	76,471	152,942
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. Foster Creek and Christina Lake are producing and Narrows Lake is in the initial stages of development. These projects are located in the Athabasca region of northeastern Alberta. Two of our 100 percent owned emerging projects are Telephone Lake and Grand Rapids, located within the Borealis and Greater Pelican Lake regions, respectively.

	Three Months Ended March 31, 2015	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow	200	3
Capital Investment	413	1
Operating Cash Flow Net of Related Capital Investment	(213)	2

(1) Includes NGLs.

Conventional

Crude oil production from our Conventional business segment continues to generate predictable near-term cash flows. 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.

	Three Months Ended March 31, 2015	
($ millions)	Crude Oil [(1)]	Natural Gas
Operating Cash Flow	166	78
Capital Investment	62	4
Operating Cash Flow Net of Related Capital Investment	104	74

(1) Includes NGLs.

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

Approximately 70 percent, or 4.5 million net acres, of our conventional land is owned in fee title, which means we own the mineral rights. About 50 percent of our total conventional production comes from our fee lands. We do not pay third-party royalties where we have working interest production from fee lands. Rather, we pay mineral tax to the government that is generally lower than royalties paid to mineral interest owners. In addition, a portion of our fee lands are leased to third parties, which resulted in approximately $25 million of Operating Cash Flow in the quarter (2014 – approximately $40 million). We continue to evaluate alternatives to maximize the value of our fee lands and if an appropriate opportunity arises and market conditions warrant, we may initiate a transaction.

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.

	Three Months Ended March 31, 2015	
	Ownership Interest (percent)	**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 regional North American crude oil differential fluctuations. 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, 2015**
Operating Cash Flow	**95**
Capital Investment	**44**
Operating Cash Flow Net of Related Capital Investment	**51**

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

The challenges of the current commodity price environment continued to significantly impact our industry in the first quarter of 2015. Average crude oil benchmark prices fell between 28 and 42 percent compared with the fourth quarter of 2014 and between 49 and 55 percent compared with the first quarter of 2014. Forward commodity prices are expected to be low for the remainder of 2015. The forward price of Western Canadian Select ("WCS") is expected to average approximately US$40 per barrel for the remainder of 2015. Maintaining financial resilience, capital spending restraint and conservation of cash are extremely important in this low commodity price environment.

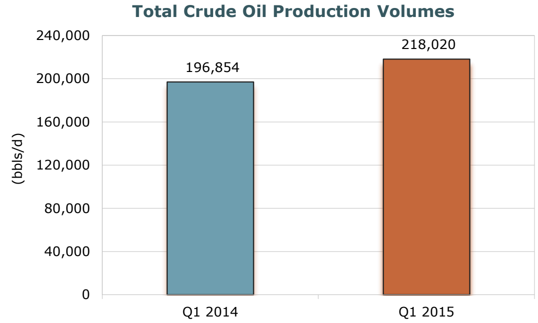
Cenovus remains well positioned to manage through these volatile times. To help preserve our financial flexibility, we completed the following in the first quarter:

- Significantly reduced our 2015 capital budget in January in an effort to exercise further capital spending restraint. We anticipate 2015 capital investment will continue to focus on base business and our oil sands expansion phases that are expected to generate near-term cash flow;
- Reducing our discretionary spend and realigning our workforce, including reducing the size of our contract workforce, based on our revised spending plans;
- Issued 67.5 million common shares at $22.25 per share for net proceeds of $1.4 billion. We intend to use the net proceeds to partially fund our 2015 capital expenditure program and for general corporate purposes. The net proceeds from this financing combined with $3 billion available on our committed credit facility, provides us with a stronger balance sheet and increased financial flexibility; and
- Initiated a three percent discount to the average market price for shareholders participating in our DRIP. For our first quarter dividend, we had a participation rate of approximately 37 percent, resulting in cash savings of $81 million.

Operational Results

Both our upstream and refining assets have performed well in the first quarter. Facility run times were very good, resulting in average crude oil production of 218,020 barrels per day and 469,000 gross barrels per day of refined product output, up 11 percent and 12 percent from 2014, respectively.

Crude oil production from our Oil Sands segment averaged 144,372 barrels per day, an increase of 20 percent. Production from Foster Creek averaged 67,901 barrels per day, an increase of 24 percent, primarily due to phase F coming on stream in September 2014 and ramping up as expected, and increased production from additional wells including wells using our Wedge Well™ technology. Phase F is our eleventh oil sands phase.



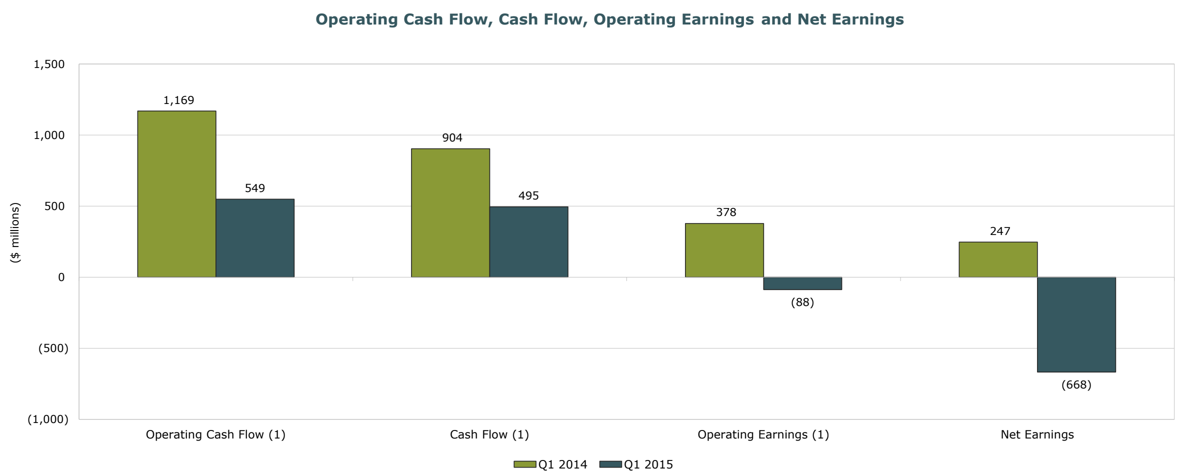
Average production at Christina Lake increased to 76,471 barrels per day, a 16 percent increase. The increase was due to phase E reaching nameplate production capacity in the second quarter of 2014, additional wells including wells using our Wedge Well™ technology and improved performance of our facilities, all of which contributed to a lower steam to oil ratio ("SOR").

Our Conventional crude oil production averaged 73,648 barrels per day, a four percent decrease primarily due to the divestitures of non-core assets in 2014. The crude oil production from these non-core assets was 3,174 barrels per day in the first quarter of 2014.

Crude oil processed and refined product output increased compared with 2014. In the first quarter of 2015, the Borger refinery completed a planned turnaround. In the first quarter of 2014, we completed planned maintenance and turnarounds at both of our refineries. We processed an average of 439,000 gross barrels per day (2014 – 400,000 gross barrels per day) of crude oil, of which 220,000 gross barrels per day (2014 – 195,000 gross barrels per day) was heavy crude oil. We produced 469,000 gross barrels per day of refined products, an increase of 49,000 gross barrels per day, or 12 percent.

Financial Results

For an understanding of the trends and events that impacted our financial results, the following discussion should be read in conjunction with our 2014 annual MD&A.



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

In the first quarter of 2015, benchmark prices continued to decline resulting in a significant decrease in our financial results. Financial highlights for the first quarter of 2015 compared with 2014 include:

Operating Cash Flow

Operating Cash Flow decreased 53 percent to $549 million. Upstream Operating Cash Flow of $454 million (2014 – $924 million) declined primarily due to the low commodity price environment with our crude oil and natural gas sales prices declining by 57 percent and 32 percent, respectively.

This decrease in upstream Operating Cash Flow due to the significant decline in crude oil and natural gas sales prices was partially offset by:

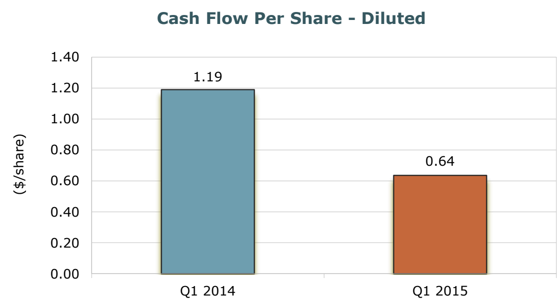
- Realized risk management gains of $137 million, excluding Refining and Marketing, compared with losses of $35 million in 2014;
- Crude oil sales volumes increasing by 11 percent;
- Lower royalties primarily due to a decline in crude oil sales prices; and

- A reduction in crude oil operating expenses of $5.13 per barrel to $12.83 per barrel, primarily related to an increase in production volumes, a decline in workover activities, lower fuel costs due to a decrease in natural gas prices, and lower repairs and maintenance costs.

Operating Cash Flow from our Refining and Marketing segment declined $150 million or 61 percent. The decrease was due to higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price and lower average market crack spreads, partially offset by improved margins on the sale of secondary products such as coke and asphalt, an increase in refined product output, and the weakening of the Canadian dollar relative to the U.S. dollar.

Cash Flow

Cash Flow decreased 45 percent to $495 million. Cash Flow was lower primarily due to a decline in Operating Cash Flow as discussed above, partially offset by a decrease in current income tax.



Operating Earnings (Loss)

Operating Earnings decreased $466 million primarily due to:

- A decrease in Cash Flow as discussed above;
- Unrealized foreign exchange losses of $9 million related to operating items as compared with gains of $53 million in 2014; and
- An increase in depreciation, depletion and amortization ("DD&A") primarily due to higher production.

These decreases were partially offset by a recovery related to employee long-term incentives and lower deferred income tax.

Net Earnings (Loss)

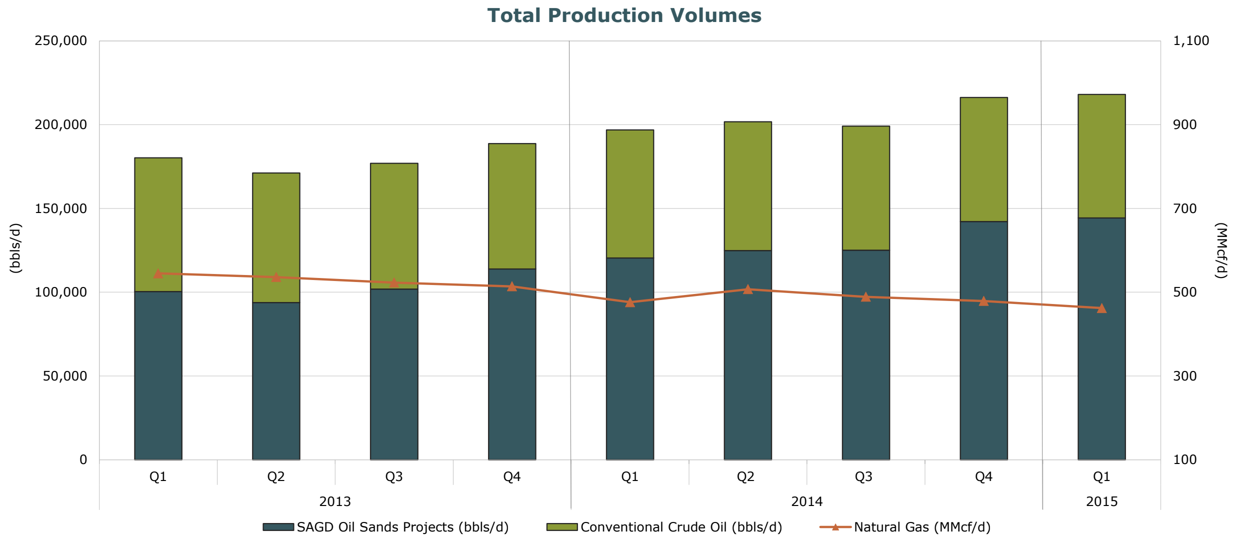
We had a Net Loss of $668 million in the quarter compared with Net Earnings of $247 million in 2014. The change was primarily related to non-operating unrealized foreign exchange losses of $514 million compared with a loss of $196 million in 2014. In addition, the decrease was due to an Operating Loss as discussed above and unrealized risk management losses compared with gains in 2014. The decrease to Net Earnings was partially offset by lower deferred income taxes.

Capital Investment

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the low commodity price environment, focusing on capital restraint and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges ahead in 2015.

Capital investment in the quarter was $529 million, a decrease of 36 percent. We have suspended the majority of our conventional drilling program in southern Alberta and Saskatchewan as a result of the current low commodity price environment. Expansion work at Foster Creek phase G and Christina Lake phase F continues. However, construction work on Foster Creek phase H, Christina Lake phase G, and Narrows Lake phase A has been deferred in response to the low commodity price environment.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	2015	Three Months Ended March 31, Percent Change	2014
Oil Sands			
Foster Creek	**67,901**	**24%**	54,706
Christina Lake	**76,471**	**16%**	65,738
	144,372	**20%**	120,444
Conventional			
Heavy Oil	**37,155**	**(9)%**	40,799
Light and Medium Oil	**35,135**	**2%**	34,598
NGLs (1)	**1,358**	**34%**	1,013
	73,648	**(4)%**	76,410
Total Crude Oil Production	**218,020**	**11%**	196,854

(1) NGLs include condensate volumes.

Foster Creek production increased compared with the first quarter of 2014 due to production from phase F coming on stream in September 2014 and ramping up as expected, and increased production from additional wells including wells using our Wedge Well™ technology. Ramp-up of phase F wells is expected to take approximately eighteen months from start up.

Production from Christina Lake increased in the first quarter due to phase E reaching nameplate production capacity in the second quarter of 2014, additional wells including wells using our Wedge Well™ technology and improved performance of our facilities, all of which contributed to a lower SOR.

Our Conventional crude oil production decreased in 2015 primarily due to the divestitures of non-core assets in 2014.

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended March 31, 2015	2014
Conventional	**442**	457
Oil Sands	**20**	19
	462	476

In the first quarter of 2015, our natural gas production declined as expected. We continue to direct the majority of our 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,	
	2015	2014	**2015**	2014
Price [2]	**31.08**	73.12	**3.05**	4.47
Royalties	**1.16**	5.74	**0.05**	0.06
Transportation and Blending [2] [3]	**5.31**	2.59	**0.12**	0.11
Operating Expenses	**12.83**	17.96	**1.26**	1.26
Production and Mineral Taxes	**0.22**	0.42	**0.01**	(0.01)
Netback Excluding Realized Risk Management	**11.56**	46.41	**1.61**	3.05
Realized Risk Management Gain (Loss)	**6.58**	(2.00)	**0.29**	-
Netback Including Realized Risk Management	**18.14**	44.41	**1.90**	3.05

(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 $22.29 per barrel for the first quarter (2014 – $34.54 per barrel).
(3) The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in the first quarter of 2014.

In the first quarter, our average crude oil netback, excluding realized risk management gains and losses, decreased $34.85 per barrel compared with 2014 primarily due to lower sales prices, consistent with the decline in benchmark prices, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. The weakening of the Canadian dollar in the first quarter had a positive impact on our crude oil price of approximately $3.50 per barrel.

Our average natural gas netback, excluding realized risk management gains and losses, decreased $1.44 per Mcf primarily due to lower sales prices consistent with the decline in the AECO benchmark price.

Refining [1]

	2015	**Percent Change**	2014
Crude Oil Runs (Mbbls/d)	**439**	**10%**	400
Heavy Crude Oil	**220**	**13%**	195
Refined Product (Mbbls/d)	**469**	**12%**	420
Crude Utilization (percent)	**95**	**8%**	87

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

Crude oil runs and refined product output increased compared to 2014. In the first quarter of 2015, we completed a planned turnaround at Borger. In the first quarter of 2014, we completed planned maintenance and turnarounds at both of our refineries.

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 Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates (1)

	Q1 2015	Percent Change	Q4 2014	Q1 2014
Crude Oil Prices (US$/bbl)				
Brent				
Average	**55.17**	**(28)%**	76.98	107.90
End of Period	**55.11**	**(4)%**	57.33	107.76
WTI				
Average	**48.63**	**(34)%**	73.15	98.68
End of Period	**47.60**	**(11)%**	53.27	101.58
Average Differential Brent-WTI	**6.54**	**71%**	3.83	9.22
WCS (2)				
Average	**33.90**	**(42)%**	58.91	75.55
End of Period	**37.30**	**(1)%**	37.59	80.71
Average Differential WTI-WCS	**14.73**	**3%**	14.24	23.13
Condensate (C5 @ Edmonton)				
Average	**45.62**	**(35)%**	70.57	102.64
Average Differential WTI-Condensate (Premium)/Discount	**3.01**	**17%**	2.58	(3.96)
Average Differential WCS-Condensate (Premium)/Discount	**(11.72)**	**1%**	(11.66)	(27.09)
Average Refined Product Prices (US$/bbl)				
Chicago Regular Unleaded Gasoline ("RUL")	**62.45**	**(23)%**	81.26	113.04
Chicago Ultra-low Sulphur Diesel ("ULSD")	**70.33**	**(31)%**	101.48	125.83
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)				
Chicago	**16.53**	**13%**	14.60	18.55
Group 3	**17.46**	**31%**	13.28	17.41
Average Natural Gas Prices				
AECO (C$/Mcf)	**2.95**	**(26)%**	4.01	4.76
NYMEX (US$/Mcf)	**2.98**	**(26)%**	4.00	4.94
Basis Differential NYMEX-AECO (US$/Mcf)	**0.57**	**30%**	0.44	0.60
Foreign Exchange Rates (US$ per C$1)				
Average	**0.806**	**(9)%**	0.881	0.906

(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 average Canadian dollar WCS benchmark price for the first quarter was $42.06 per barrel (2014 – $83.39 per barrel).

Crude Oil Benchmarks

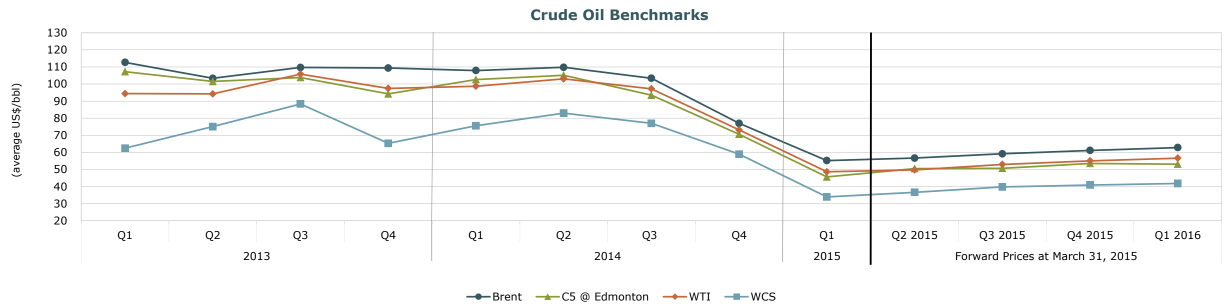
Crude oil benchmark pricing continued to decline in the first quarter of 2015 compared with the fourth quarter of 2014. The average Brent, WTI and WCS benchmark prices decreased due to a global imbalance of supply and demand which began in the last half of 2014 and persisted in the first quarter of 2015. This global imbalance was created by slowing global economic conditions outside of the U.S. and strong growth in North American crude oil supply, which was further amplified by the Organization of Petroleum Exporting Countries ("OPEC") decision to maintain its level of crude oil output and discontinue its swing supplier role. Despite significantly lower crude oil prices, the global imbalance has not materially improved to date in 2015, resulting in higher U.S. crude oil inventories which continue to put downward pressure on crude oil prices.

The Brent benchmark is representative of global crude oil prices and, we believe, a better indicator than WTI of inland refined product prices. In the first quarter of 2015, the average price of Brent crude oil decreased by US$52.73 per barrel or 49 percent compared with 2014. The decline was primarily due to the global supply and demand imbalance discussed above.

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 Brent-WTI differential narrowed in the first quarter of 2015 by US$2.68 per barrel or 29 percent as compared with 2014 as a result of new pipeline capacity to the U.S. Gulf Coast, increasing the price of WTI relative to Brent.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed by US$8.40 per barrel or 36 percent compared with the first quarter of 2014 primarily due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity providing access to existing and new U.S. heavy oil refining markets, and an increase in heavy crude oil demand with new coker capacity in the Chicago area.

Blending condensate with bitumen and heavy oil enables our current production to be transported through pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. As the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices are driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton. Compared with the first quarter of 2014, the average WTI-Condensate differential changed by US$6.97 per barrel, with condensate being sold at a discount to WTI in 2015 as compared with a premium in 2014. This change was primarily due to increased supply resulting in a sharper decline in condensate prices as compared with the decline in WTI. The average WCS-Condensate differential narrowed by US$15.37 per barrel primarily due to improved transportation infrastructure for both condensate imports into Alberta and heavy crude oil exports to market.

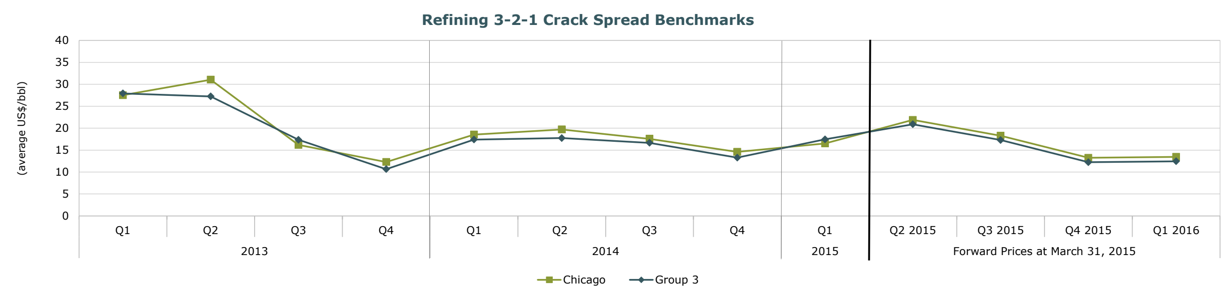


Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("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 crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average inland refined product prices decreased by 44 percent in the first quarter of 2015 as compared with 2014 due to weaker global crude oil pricing. Average Chicago 3-2-1 crack spreads fell 11 percent in the first quarter compared with 2014 due to the narrowing of the Brent-WTI differential as a result of new pipeline capacity to the U.S. Gulf Coast. Average Group 3 crack spreads increased slightly as a result of unplanned refinery outages resulting in slightly improved refined product pricing.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil inputs, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.



Natural Gas Benchmarks

Average natural gas prices decreased in the first quarter of 2015 primarily due to an increase in supply from the U.S.

Foreign Exchange Benchmarks

All of our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, we have chosen to borrow U.S. dollar long-term debt. In periods of a weakening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange losses when translated to Canadian dollars.

In the first quarter of 2015, the Canadian dollar weakened by $0.10, or 11 percent, compared with 2014 relative to the U.S. dollar due to weaker commodity prices and the strengthening of the U.S. economy. The weakening of the Canadian dollar had a positive impact of approximately $350 million on our revenues and also resulted in an increase of $318 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3	2013 Q2	2013 Q1
Revenues	**3,141**	4,238	4,970	5,422	5,012	4,747	5,075	4,516	4,319
Operating Cash Flow (1)	**549**	539	1,154	1,296	1,169	976	1,153	1,125	1,214
Cash Flow (1)	**495**	401	985	1,189	904	835	932	871	971
Per Share – Diluted	**0.64**	0.53	1.30	1.57	1.19	1.10	1.23	1.15	1.28
Operating Earnings (Loss) (1)	**(88)**	(590)	372	473	378	212	313	255	391
Per Share – Diluted	**(0.11)**	(0.78)	0.49	0.62	0.50	0.28	0.41	0.34	0.52
Net Earnings (Loss)	**(668)**	(472)	354	615	247	(58)	370	179	171
Per Share – Basic	**(0.86)**	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23
Per Share – Diluted	**(0.86)**	(0.62)	0.47	0.81	0.33	(0.08)	0.49	0.24	0.23
Capital Investment (2)	**529**	786	750	686	829	898	743	706	915
Dividends									
Cash Dividends	**138**	201	201	201	202	183	182	183	184
In Shares from Treasury	**84**	-	-	-	-	-	-	-	-
Per Share	**0.2662**	0.2662	0.2662	0.2662	0.2662	0.242	0.242	0.242	0.242

(1) Non-GAAP measure defined in this MD&A.
(2) Includes expenditures on PP&E and Exploration and Evaluation ("E&E") assets.

Revenues

In the first quarter, revenues decreased $1,871 million or 37 percent compared with 2014 primarily due to the significant decline in commodity prices.

Upstream revenues declined by 42 percent primarily due to sharp declines in our crude oil blend and natural gas sales prices, consistent with the 55 percent decrease in WCS and 38 percent decrease in the AECO benchmark price.

($ millions)	
Revenues for the Three Months Ended March 31, 2014	**5,012**
Increase (Decrease) due to:	
Oil Sands	**(480)**
Conventional	**(364)**
Refining and Marketing	**(1,162)**
Corporate and Eliminations	**135**
Revenues for the Three Months Ended March 31, 2015	**3,141**

The decrease to upstream revenues was partially offset by:

- Crude oil sales volumes increasing 11 percent; and
- A decrease in royalties of $79 million primarily due to a decline in crude oil sales prices.

Revenues generated by our Refining and Marketing segment decreased 36 percent. Refining revenues declined due to the continued decrease in refined product pricing consistent with lower Chicago RUL and Chicago ULSD benchmark prices, partially offset by higher refined product output and the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group decreased primarily due to a decline in crude oil and natural gas sales prices, partially offset by an increase in purchased crude oil volumes.

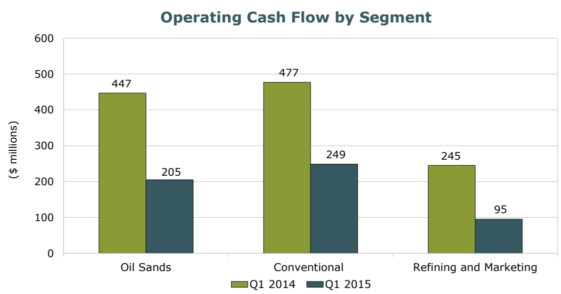
Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

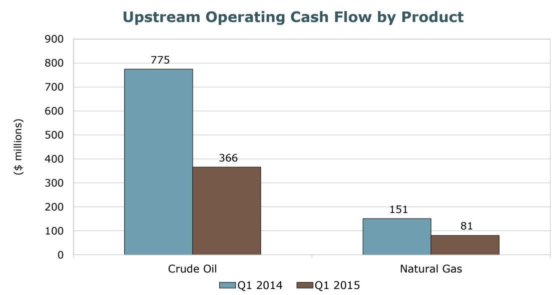
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

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)	**2015**	2014
Revenues	**3,247**	5,253
(Add) Deduct:		
Purchased Product	**1,838**	2,820
Transportation and Blending	**528**	653
Operating Expenses	**478**	574
Production and Mineral Taxes	**5**	7
Realized (Gain) Loss on Risk Management Activities	**(151)**	30
Operating Cash Flow	**549**	1,169





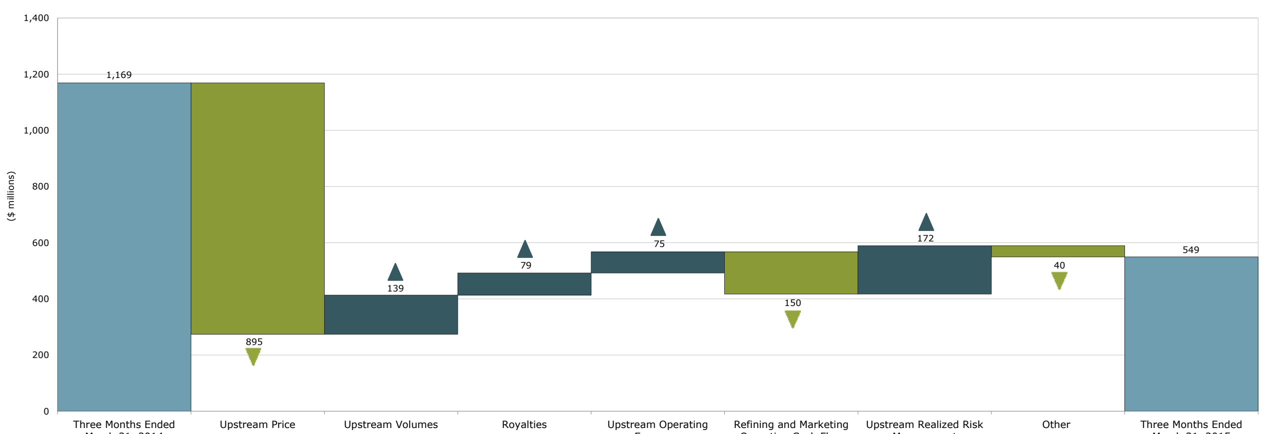
As highlighted in the graph below, Operating Cash Flow declined 53 percent in the first quarter as compared with 2014 primarily due to:

- A 57 percent decrease in our average crude oil sales price to $31.08 per barrel and a 32 percent decrease in our average natural gas sales price to $3.05 per Mcf, consistent with the sharp drop in associated benchmark prices; and
- Lower Operating Cash Flow from Refining and Marketing as a result of higher heavy crude oil feedstock costs relative to WTI and a decrease in average market crack spreads, partially offset by improved margins on the sale of secondary products due to lower overall feedstock costs, an increase in refined product output, and the weakening of the Canadian dollar relative to the U.S. dollar.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $137 million, excluding Refining and Marketing, compared with losses of $35 million in 2014;
- An 11 percent increase in our crude oil sales volumes;
- Lower royalties primarily due to a decrease in crude oil and natural gas sales prices; and
- A decrease in crude oil operating expenses of $5.13 per barrel to $12.83 per barrel primarily due to higher crude oil production, a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs.

Operating Cash Flow Variance



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

Cash Flow

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

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Cash From Operating Activities	**275**	457
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(54)**	(42)
Net Change in Non-Cash Working Capital	**(166)**	(405)
Cash Flow	**495**	904

In the first quarter of 2015, Cash Flow decreased $409 million primarily due to lower Operating Cash Flow, as discussed above. Declines in Cash Flow were partially offset by a current income tax recovery in 2015.

Operating Earnings (Loss)

Operating Earnings (Loss) 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 (Loss) is defined as Earnings (Loss) 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, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax.

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Earnings (Loss), Before Income Tax	**(781)**	358
Add (Deduct):		
Unrealized Risk Management (Gain) Loss [(1)]	**145**	(26)
Non-operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**514**	196
(Gain) Loss on Divestiture of Assets	**(16)**	-
Operating Earnings (Loss), Before Income Tax	**(138)**	528
Income Tax Expense (Recovery)	**(50)**	150
Operating Earnings (Loss)	**(88)**	378

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

In the first quarter of 2015, Operating Earnings decreased $466 million primarily due to:

- A decrease in Cash Flow as discussed above;
- Unrealized foreign exchange losses of $9 million related to operating items as compared with gains of $53 million in 2014; and
- An increase in DD&A primarily related to higher sales volumes from our Oil Sands assets.

These decreases were partially offset by a recovery of employee long-term incentive costs compared with an expense in 2014 and lower deferred income tax primarily related to a decrease in income before income tax.

Net Earnings (Loss)

($ millions)	
Net Earnings for the Three Months Ended March 31, 2014	**247**
Increase (Decrease) due to:	
Operating Cash Flow [(1)]	**(620)**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**(171)**
Unrealized Foreign Exchange Gain (Loss)	**(380)**
Gain (Loss) on Divestiture of Assets	**16**
Expenses [(2)]	**61**
Depreciation, Depletion and Amortization	**(45)**
Income Tax Expense	**224**
Net Earnings (Loss) for the Three Months Ended March 31, 2015	**(668)**

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

Net Earnings decreased $915 million in the first quarter of 2015 primarily due to:

- A decline in Operating Earnings of $466 million as discussed above;
- Non-operating unrealized foreign exchange losses of $514 million (2014 – unrealized losses of $196 million); and
- Unrealized risk management losses of $145 million (2014 – unrealized gains of $26 million).

The decreases in Net Earnings were partially offset by:

- Lower deferred income taxes as a result of a decrease in Canadian and U.S. income and unrealized risk management losses compared with a gain in 2014.

Net Capital Investment

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Oil Sands	**414**	527
Conventional	**66**	270
Refining and Marketing	**44**	23
Corporate and Eliminations	**5**	9
Capital Investment	**529**	829
Acquisitions	**-**	1
Divestitures	**(16)**	(2)
Net Capital Investment (1)	**513**	828

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the low commodity price environment, with a focus on capital restraint and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges in 2015.

Capital investment in the first quarter of 2015 was $529 million, a decrease of 36 percent. In January, we reduced our planned capital investment with the intent of conserving cash and maintaining the strength of our balance sheet in light of the continued low commodity price environment. We plan to focus 2015 capital investment on ensuring our assets are appropriately maintained, meet safety, regulatory and contractual obligations, and on our Christina Lake phase F and Foster Creek phase G expansions.

In the first quarter of 2015, Oil Sands capital investment focused primarily on sustaining capital related to existing production, phase G expansion at Foster Creek, Christina Lake's phase F expansion and the optimization project, and the drilling of 158 gross stratigraphic test wells which were primarily related to near-term phase expansions to determine pad placement.

Conventional capital investment focused primarily on maintenance capital and spending for our CO_2 project at Weyburn.

Our capital investment in the Refining and Marketing segment focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives.

Capital also includes spending on technology development, which plays an integral role in our business. Having a strategy focused on innovation and technology development 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, which was primarily for computer equipment.

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:

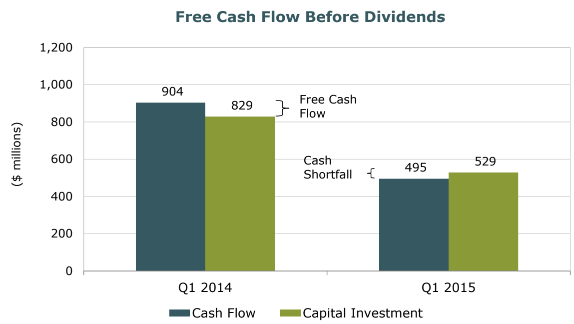
- First, to committed capital, which is the capital spending required for continued progress on approved expansions at our multi-phase projects, and capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth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

Our approach to capital allocation 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. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. We anticipate maintaining investment grade credit ratings.

In January 2015, in light of the current low commodity price environment, we revised our 2015 capital budget in order to help conserve cash and maintain the strength of our balance sheet. We anticipate our total annual capital investment to be between $1.8 billion and $2.0 billion for 2015. Our capital budget has a degree of flexibility and, as such, we will continue to assess spending plans on a regular basis and make adjustments, if required. Refer to the Reportable Segments section of this MD&A for more details and the news release for our revised 2015 budget dated January 28, 2015. The news release is available on our website at cenovus.com, on SEDAR at sedar.com and on EDGAR at sec.gov.

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Cash Flow [1]	**495**	904
Capital Investment (Committed and Growth)	**529**	829
Free Cash Flow [2]	**(34)**	75
Cash Dividends	**138**	202
	(172)	(127)

(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.



Cash flow from our crude oil, natural gas and refining operations is expected to fund a portion of our cash requirements, with any remainder expected to be funded through prudent use of our balance sheet capacity and management of our asset portfolio. In the first quarter of 2015 we issued 67.5 million common shares for net proceeds of $1.4 billion. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

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 Cenovus'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 responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.

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, financing activities and research costs. 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.

Revenues by Reportable Segment

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Oil Sands	**729**	1,209
Conventional	**422**	786
Refining and Marketing	**2,096**	3,258
Corporate and Eliminations	**(106)**	(241)
	3,141	5,012

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 development, 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 developments in our Oil Sands segment in the first quarter of 2015 compared with 2014 include Foster Creek production increasing 24 percent, to an average of 67,901 barrels per day and Christina Lake production increasing 16 percent, to an average of 76,471 barrels per day as facility run times were very good. Foster Creek production increased primarily as a result of phase F coming on stream. Christina Lake production rose primarily due to phase E reaching nameplate production capacity in the second quarter of 2014.

Oil Sands – Crude Oil

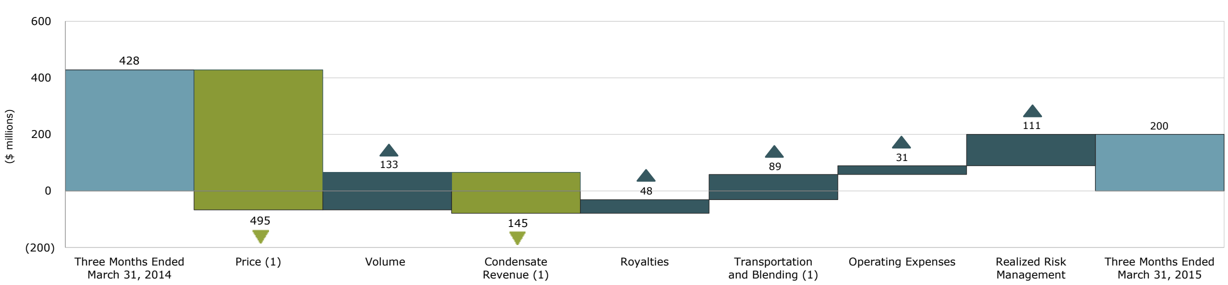
Financial and Per-unit Results

	Three Months Ended March 31, 2015		Three Months Ended March 31, 2014	
($ millions, unless otherwise noted [1])		$ per-unit		$ per-unit
Gross Sales	**723**	57	1,230	116
Less: Royalties	**3**	-	51	5
Revenues	**720**	57	1,179	111
Expenses				
Transportation and Blending	**470**	37	559	53
Operating	**139**	11	170	16
(Gain) Loss on Risk Management	**(89)**	(7)	22	2
Operating Cash Flow	**200**	16	428	40
Capital Investment	**413**		525	
Operating Cash Flow Net of Related Capital Investment	**(213)**		(97)	

(1) Per-unit amounts are calculated on an unblended crude oil basis.

Capital investment in excess of Operating Cash Flow from Oil Sands is funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments and proceeds from our common share issuance in the first quarter of 2015.

Operating Cash Flow Variance



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

Revenues

Pricing

In the first quarter, our average crude oil sales price was $26.04 per barrel, a 60 percent decrease from 2014 as the prices we received continued to be impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market which secure a higher sales price. The WCS-CDB differential narrowed by 34 percent to a discount of US$3.21 per barrel (2014 – a discount of US$4.90 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process heavier crude oil. In the first quarter, 86 percent of our Christina Lake production was sold as CDB (2014 – 84 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2015	Percent Change	2014
Foster Creek	**67,901**	**24%**	54,706
Christina Lake	**76,471**	**16%**	65,738
	144,372	**20%**	120,444

Foster Creek production increased compared with the first quarter of 2014 due to production from phase F coming on stream in September 2014, and increased production from additional wells including wells using our Wedge Well™ technology. Ramp-up of phase F wells is proceeding as expected and is anticipated to take approximately eighteen months from start up.

Production from Christina Lake increased in the first quarter due to phase E reaching nameplate production capacity in the second quarter of 2014, a higher number of wells including wells using our Wedge Well™ technology and improved performance of our facilities, all of which contributed to a lower SOR.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

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

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

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

Effective Royalty Rates

(percent)	Three Months Ended March 31, 2015	2014
Foster Creek	**(1.2)**	8.1
Christina Lake	**3.1**	7.1

Royalties decreased $48 million in the first quarter of 2015, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, this resulted in a royalty calculation based on gross revenues in the first quarter of 2015 compared with a calculation based on net profits in 2014.

In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation which has resulted in a negative royalty rate at Foster Creek for the quarter. We recorded the associated credit in the first quarter of 2015. Excluding the credit, the effective royalty rate for Foster Creek would have been 5.9 percent.

Expenses

Transportation and Blending

Transportation and blending costs decreased $89 million or 16 percent. Blending costs declined primarily due to lower condensate prices, partially offset by an increase in condensate volumes consistent with the rise in production. Our condensate costs were higher than the average benchmark price in 2015 primarily due to the utilization of higher priced inventory and the transportation expense associated with moving the condensate to our oil sands projects.

Transportation costs increased $62 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To ensure adequate capacity for our expected future production growth, we hold long-term transportation agreements on the Cold Lake pipeline expansion. Deliveries commenced in the first quarter of 2015. We also have capacity on the Flanagan South system, which will increase our sales opportunities into the U.S. market which secure a higher sales price. Deliveries on the Flanagan South system began in the fourth quarter of 2014. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes transported by rail. In the first quarter of 2015, we transported an average of 11,871 gross barrels per day of crude oil by rail, consisting of 18 unit train shipments (2014 – 1,964 gross barrels per day, including three unit train shipments). Rail transportation costs are generally higher than pipeline costs; however, rail provides flexibility in destinations, products transported and the duration of the cost commitment, which is typically shorter in term than pipeline commitments.

Operating

Primary drivers of our operating expenses in the first quarter of 2015 were workforce, fuel, workovers and repairs and maintenance. Total operating expenses decreased $31 million or $4.99 per barrel, primarily as a result of higher production, lower natural gas prices that reduced fuel costs, and a decline in workover activities.

Per-unit Operating Expenses

	Three Months Ended March 31,		
($/bbl)	**2015**	**Percent Change**	2014
Foster Creek			
Fuel	**2.96**	**(46)%**	5.45
Non-fuel	**11.52**	**(16)%**	13.64
Total	**14.48**	**(24)%**	19.09
Christina Lake			
Fuel	**2.19**	**(55)%**	4.83
Non-fuel	**6.03**	**(29)%**	8.47
Total	**8.22**	**(38)%**	13.30
Total	**10.97**	**(31)%**	15.96

At Foster Creek, fuel costs decreased $2.49 per barrel primarily due to the decline in natural gas prices. Non-fuel operating expenses declined $2.12 per barrel, primarily due to:

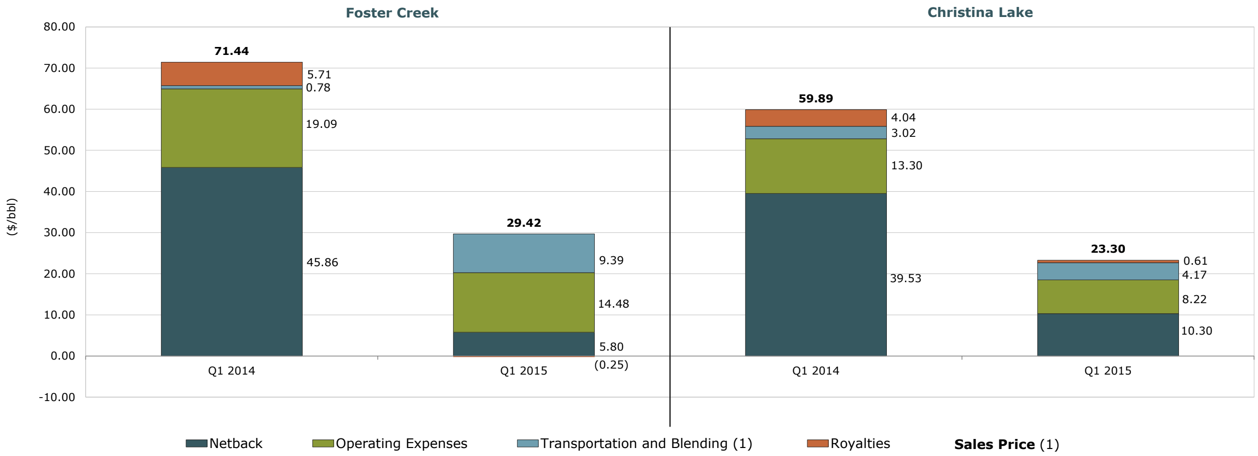
- Higher production volumes;
- A reduction in workover activities related to well servicing, primarily due to fewer pump changes; and
- A decline in electricity costs due to lower prices.

The decrease in non-fuel operating expenses was partially offset by higher chemical costs.

At Christina Lake, fuel costs decreased by $2.64 per barrel due to the decline in natural gas prices and a decrease in fuel consumption on a per barrel basis. Non-fuel operating expenses decreased $2.44 per barrel, primarily due to:

- Increased production;
- Declines in fluid, waste handling and trucking costs related to the optimization of the chemical application process;
- Lower workover activities related to well servicing, primarily due to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities.

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 $30.57 per barrel (2014 – $48.35 per barrel) for Foster Creek; and $31.60 per barrel (2014 – $52.81 per barrel) for Christina Lake.*

Risk Management

Risk management activities in the first quarter resulted in realized gains of $89 million (2014 – realized losses of $22 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands includes our 100 percent-owned natural gas operations in Athabasca. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production for the first quarter of 2015, net of internal usage, was 20 MMcf per day (2014 – 19 MMcf per day). Operating Cash Flow was $3 million in the first quarter (2014 – $23 million). The decrease was primarily related to the decline in natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2015	2014
Foster Creek	**149**	221
Christina Lake	**207**	182
	356	403
Narrows Lake	**20**	47
Telephone Lake	**11**	52
Grand Rapids	**14**	11
Other [(1)]	**13**	14
Capital Investment [(2)]	**414**	527

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

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the low commodity price environment, with a focus on capital restraint and conservation of cash. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexibility in our capital plans, which should allow us to face the challenges in 2015. We plan to focus our 2015 capital investment on base business and our oil sands expansion phases that are expected to generate near-term cash flow.

Existing Projects

Capital investment at Foster Creek in the first quarter focused on sustaining capital related to existing production, expansion phase G and the drilling of stratigraphic test wells primarily related to future sustaining well pads. Capital investment declined compared with 2014 due to lower spending related to field construction and completion costs with the commissioning of phase F in 2014 and the drilling of fewer stratigraphic test wells.

In the first quarter, Christina Lake capital investment focused on sustaining capital related to existing production, expansion phase F and the optimization project. Capital investment increased due to higher spending on sustaining wells; phase G engineering and procurement; phase F well pads; and progressing the optimization project.

Capital investment at Narrows Lake focused on detailed engineering and procurement for phase A. Capital investment declined due to the suspension of new construction on phase A until further notice.

Emerging Projects

In the first quarter, Telephone Lake capital investment was primarily focused on front-end engineering work on the central processing facility. Capital spending decreased as we did not drill any stratigraphic test wells in the first quarter (2014 – 31 stratigraphic test wells).

Capital investment at Grand Rapids in the first quarter was primarily focused on the drilling of a third pilot well pair at the SAGD pilot project to gather additional information on the reservoir. Capital investment increased due to the dismantling, removal and storage of an existing SAGD facility purchased in 2014, partially offset by the lack of stratigraphic test wells drilled in 2015.

Drilling Activity (1)

	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3) (4)	
	Three Months Ended March 31,			
	2015	2014	**2015**	2014
Foster Creek	**122**	145	**13**	15
Christina Lake	**36**	51	**19**	18
	158	196	**32**	33
Narrows Lake	**-**	22	**-**	-
Telephone Lake	**-**	31	**-**	-
Grand Rapids	**-**	9	**1**	-
Other	**-**	21	**-**	-
	158	279	**33**	33

(1) In addition to the drilling activity included within the table, we drilled five gross service wells in the first quarter (2014 – one gross service well).
(2) Includes wells drilled using our SkyStrat™ drilling rig, which uses a helicopter and a lightweight drilling rig to allow safe stratigraphic well drilling to occur year-round in remote drilling locations. In the first quarter, we drilled seven wells (2014 – no wells drilled) and commissioned our second SkyStrat™ drilling rig.
(3) SAGD well pairs are counted as a single producing well.
(4) Includes wells drilled using our Wedge Well™ technology.

Future Capital Investment

Due to our expectation that the low commodity price environment will continue for the near term, we decided in January to slow 2015 capital activities in order to conserve cash and maintain the strength of our balance sheet. For more details, refer to our January 28, 2015 news release available on our website at cenovus.com, on SEDAR at sedar.com and on EDGAR at sec.gov. Our capital budget has a degree of flexibility and as such we will continue to assess spending plans on a regular basis and make adjustments, if required.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 is forecast to be between $550 million and $600 million and we plan to focus on sustaining capital related to existing production as well as progressing expansion phase G. We expect phase G to add initial design capacity of 30,000 gross barrels per day and first production is anticipated in the first half of 2016. Spending related to construction work on phase H has been deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase H has an initial design capacity of 30,000 barrels per day. In December 2014, we received regulatory approval for expansion phase J, a 50,000 gross barrel per day phase.

Christina Lake is producing from phases A through E. Capital investment in 2015 is forecast to be between $650 million and $700 million and we plan to focus on sustaining capital related to existing production, expansion phase F and the optimization project. Expansion work on phase F, including cogeneration, is expected to continue as planned. We anticipate adding production capacity of 50,000 gross barrels per day from phase F in the second half of 2016. The optimization project is expected to add production capacity of 22,000 gross barrels per day in the fourth quarter of 2015. Spending related to construction work on phase G has been deferred in response to the low commodity price environment, pushing the expected start-up to beyond 2017. Phase G engineering and procurement are planned to continue in 2015. Phase G has an initial design capacity of 50,000 gross barrels per day. We submitted a joint application and environmental impact assessment to regulators in March 2013 for the phase H expansion, a 50,000 gross barrel per day phase, for which we expect to receive regulatory approval in the second quarter of 2015.

Capital investment at Narrows Lake is forecast to be between $30 million and $40 million in 2015. In 2015, we plan to focus our capital investment on detailed engineering and procurement. We have suspended new construction on phase A until crude oil prices recover.

Emerging Projects

Two of our emerging projects are Telephone Lake and Grand Rapids. Capital investment for our new resource plays is forecast to be between $90 million and $100 million in 2015. We plan to focus on continuing the pilot project at Grand Rapids; the dismantling, removal and storage of an existing SAGD facility purchased in 2014; as well as engineering at Telephone Lake. At Grand Rapids, we drilled a third pilot well pair in the first quarter of 2015 and we plan to commence steam circulation in the second quarter, as we continue to operate the SAGD pilot project to gather additional information on the reservoir.

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. 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.

In the first quarter of 2015, Oil Sands DD&A increased $27 million primarily due to 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, our heavy oil asset 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. The cash flow generated in our Conventional operations helps to fund future growth opportunities in our Oil Sands segment.

We own the mineral rights on approximately 70 percent or 4.5 million net acres of our conventional lands (fee lands), of which 2.5 million acres are developed. Production from fee lands comprises approximately 50 percent of our total conventional production. Fee lands where we have maintained working interest production are subject to mineral tax, which is generally lower than the royalties paid to the government or other mineral interest owners.

Of the 4.5 million net acres of fee land, we lease over 2.0 million acres to third parties, which may result in royalty income. In the first quarter of 2015, we had approximately 7,400 barrels of oil equivalent per day of royalty interest production from fee lands which resulted in Operating Cash Flow of approximately $25 million (2014 – approximately $40 million).

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.

Significant developments in our Conventional segment in the first quarter of 2015 compared with 2014 include:

- Crude oil production averaging 73,648 barrels per day, decreasing four percent primarily due to the divestitures of non-core assets in 2014; and
- Generating Operating Cash Flow net of capital investment of $183 million, a decrease of 12 percent.

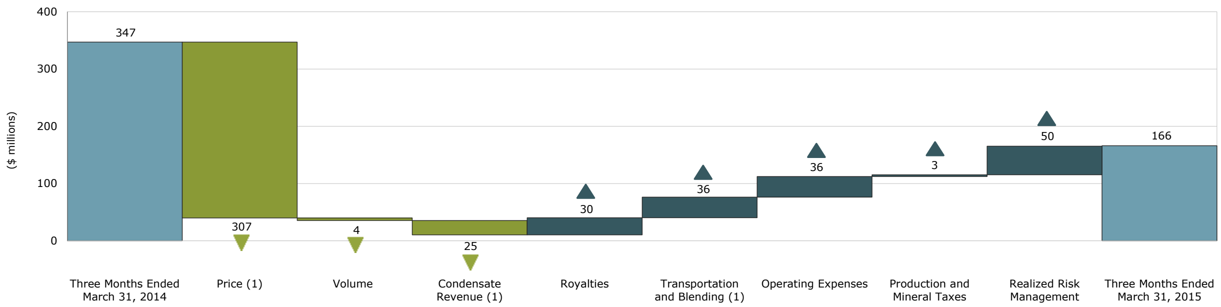
Conventional – Crude Oil

Financial and Per-unit Results

($ millions, unless otherwise noted [1])	Three Months Ended March 31, 2015	$ per-unit	Three Months Ended March 31, 2014	$ per-unit
Gross Sales	**315**	46	651	95
Less: Royalties	**19**	3	49	7
Revenues	**296**	43	602	88
Expenses				
Transportation and Blending	**53**	8	89	13
Operating	**109**	16	145	21
Production and Mineral Taxes	**5**	1	8	1
(Gain) Loss on Risk Management	**(37)**	(5)	13	2
Operating Cash Flow	**166**	23	347	51
Capital Investment	**62**		263	
Operating Cash Flow Net of Related Capital Investment	**104**		84	

(1) *Per-unit amounts are calculated on an unblended crude oil basis.*

Operating Cash Flow Variance



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

Revenues

Pricing

Our average crude oil sales price decreased 53 percent to $40.43 per barrel consistent with the continued decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**37,155**	**(9)%**	40,799
Light and Medium Oil	**35,135**	**2%**	34,598
NGLs	**1,358**	**34%**	1,013
	73,648	**(4)%**	76,410

Production declined primarily due to the divestiture of non-core assets in 2014.

Condensate

Revenues represent the total value of blended crude oil sold and include the value of condensate.

Royalties

Royalties decreased $30 million primarily due to lower realized sales prices. In the first quarter, the effective crude oil royalty rate for our Conventional properties was 7.5 percent (2014 – 9.0 percent).

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, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and realized sales prices. Net profits are a function of sales volumes, realized sales prices and allowed operating and capital costs. In the first quarter of 2015, the Pelican Lake royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2014.

Approximately 50 percent of our production is not subject to royalties, rather is subject to mineral tax which is generally lower than the royalties paid to the government or other mineral interest owners. In the first quarter of 2015, production and mineral taxes decreased, consistent with the decline in crude oil prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $36 million. Blending costs declined primarily due to lower condensate prices. In the first quarter of 2015, we recorded a $3 million write-down of our crude oil inventory to net realizable value as a result of the continued decline in crude oil prices. Transportation charges were $2 million lower primarily due to a decrease in volumes moved by rail. In the first quarter of 2015, we transported an average of 1,591 gross barrels per day of crude oil by rail (2014 – 5,497 barrels per day).

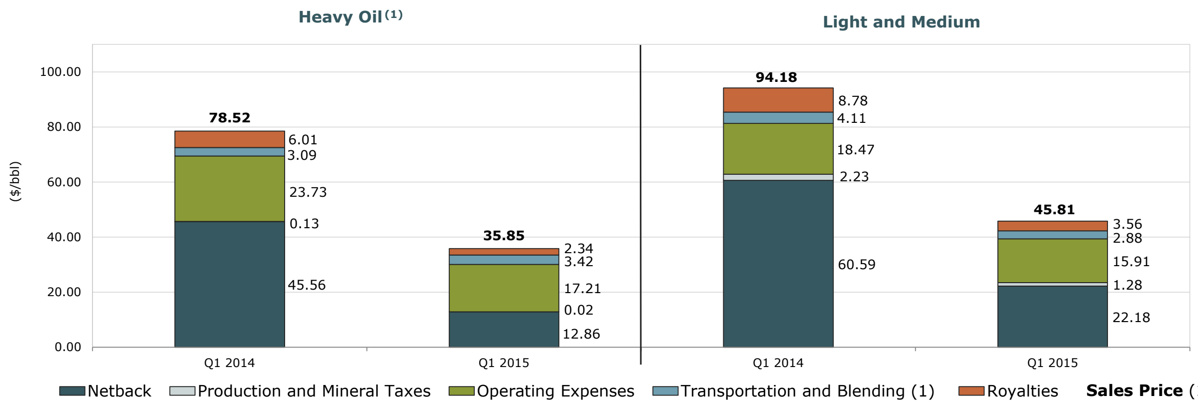
Operating

Primary drivers of our operating expenses in the first quarter of 2015 were workforce costs, workover activities, chemical consumption, electricity and repairs and maintenance. Operating expenses declined $36 million or $4.77 per barrel.

The per unit decline was primarily due to:

- A decline in workover costs and lower repairs and maintenance due to a focus on critical operational activities;
- Lower electricity costs as a result of a decrease in consumption related to the dispositions of non-core assets, and a decline in prices; and
- A decrease in fuel costs primarily related to a decline in consumption and lower fuel prices.

Operating Netbacks



(1) *The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended heavy oil basis, the cost of condensate for our heavy oil properties was $11.50 per barrel in the first quarter (2014 – $17.56 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

(2) *The netbacks do not reflect non-cash write-downs of product inventory. There was no product inventory write-down recorded in the first quarter of 2014.*

Risk Management

Risk management activities in the first quarter resulted in realized gains of $37 million (2014 – realized losses of $13 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended March 31, 2015	2014
Gross Sales	**122**	184
Less: Royalties	**2**	3
Revenues	**120**	181
Expenses		
Transportation and Blending	**5**	5
Operating	**47**	49
Production and Mineral Taxes	**-**	(1)
(Gain) Loss on Risk Management	**(10)**	-
Operating Cash Flow	**78**	128
Capital Investment	**4**	7
Operating Cash Flow Net of Related Capital Investment	**74**	121

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

Revenues

Pricing

In the first quarter of 2015, our average natural gas sales price decreased $1.39 per Mcf to $3.07 per Mcf, consistent with the continued decline in the AECO benchmark price.

Production

Production decreased three percent to 442 MMcf per day primarily due to expected natural declines.

Royalties

Royalties decreased slightly as a result of lower prices and production declines. The average royalty rate in the first quarter was 1.7 percent (2014 – 1.3 percent). Most of our natural gas production is located on fee lands where we hold mineral rights and is not subject to royalties. Instead, this production is subject to mineral tax which is generally lower than royalties paid to the government or other mineral rights owners.

Expenses

Transportation

Transportation costs remained consistent as a result of lower production volumes, offset by higher pipeline rates.

Operating

In the first quarter of 2015, our operating expenses were primarily composed of property taxes and lease costs, and workforce. Operating expenses decreased slightly primarily due to lower electricity costs, partially offset by higher property taxes and lease costs.

Risk Management

Risk management activities in the first quarter resulted in realized gains of $10 million (2014 – $nil), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment [1]

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Heavy Oil	**22**	106
Light and Medium Oil	**40**	157
Natural Gas	**4**	7
	66	270

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

Capital investment in the first quarter was primarily related to maintenance capital and spending for our CO_2 project at Weyburn. Spending on crude oil and natural gas activities continues to be managed in response to the low commodity price environment.

Conventional Drilling Activity

	Three Months Ended March 31,	
(net wells, unless otherwise stated)	**2015**	2014
Crude Oil	**5**	52
Recompletions	**34**	223
Gross Stratigraphic Test Wells	**-**	13
Other [1]	**-**	16

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

Drilling activity declined in the first quarter, reflecting the decision to suspend the majority of our 2015 drilling program in southern Alberta and Saskatchewan as a result of the current low commodity price environment.

Future Capital Investment

In 2015, crude oil capital investment is forecast to be between $200 million and $215 million with spending plans mainly focused on maintenance capital and spending for our CO_2 project at Weyburn.

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. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by total proved reserves.

Conventional DD&A increased $10 million in the first quarter of 2015. The increase was primarily due to higher DD&A rates related to a decrease in proved reserves.

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 approach 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. The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent in the first quarter of 2015 as compared with 2014 had a positive impact of approximately $26 million on our refining gross margin.

Significant developments in our Refining and Marketing segment in the first quarter of 2015 compared with 2014 include:

- Crude oil runs and refined product output increasing as a result of the timing of planned maintenance and turnaround activities;
- Operating Cash Flow declining 61 percent to $95 million primarily due to higher heavy crude oil feedstock costs relative to WTI and lower average market crack spreads, partially offset by improved margins on the sale of secondary products, an increase in refined product output, and the weakening of the Canadian dollar relative to the U.S. dollar; and
- Successfully completed a planned turnaround at our Borger refinery.

Refinery Operations (1)

	Three Months Ended March 31, 2015	2014
Crude Oil Capacity (2) (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**439**	400
Heavy Crude Oil	**220**	195
Light/Medium	**219**	205
Refined Products (Mbbls/d)	**469**	420
Gasoline	**236**	215
Distillate	**144**	130
Other	**89**	75
Crude Utilization (percent)	**95**	87

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) The official nameplate capacity, based on 95 percent of the highest average rate achieved over a continuous 30 day period.

On a 100 percent basis, our refineries have total 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 benefits our refining operations due to the feedstock cost advantage provided by processing heavy crude oil.

In the first quarter of 2015, crude oil runs, refined product output and crude utilization increased as a result of reduced output in 2014 primarily due to planned maintenance and turnarounds at both of our refineries. In the first quarter of 2015, we completed a planned turnaround at Borger.

Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity. Due to our ability to process a wide slate of crude oils, a feedstock cost advantage is created by processing less expensive crude oil. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate being optimized at each refinery to maximize economic benefit. The amount of heavy crude oil processed in the first quarter of 2015 increased, consistent with the increase in total crude oil runs.

Financial Results

($ millions)	Three Months Ended March 31, 2015	2014
Revenues	**2,096**	3,258
Purchased Product	**1,838**	2,820
Gross Margin	**258**	438
Expenses		
Operating	**177**	198
(Gain) Loss on Risk Management	**(14)**	(5)
Operating Cash Flow	**95**	245
Capital Investment	**44**	23
Operating Cash Flow Net of Related Capital Investment	**51**	222

Gross Margin

Our realized crack spreads are affected by many factors such as the variety of feedstock crude oil inputs, refinery configuration and the proportion of gasoline, distillate and secondary product output, the time lag between the purchase of crude oil feedstock and the processing of that crude oil through our refineries, and the cost of feedstock. Our feedstock costs are valued on a FIFO accounting basis.

In the first quarter of 2015, the decrease in gross margin was primarily due to:

- Higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential; and
- Lower average market crack spreads, which decreased by approximately five percent, primarily due to the narrowing of the Brent-WTI differential.

The decrease in gross margin was partially offset by:

- Improved margins on the sale of secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the 51 percent decline in WTI;
- An increase in refined product output by 12 percent; and
- The weakening of the Canadian dollar relative to the U.S. dollar by 11 percent.

Our refineries do not blend renewable fuels into the motor fuel products we produce. Consequently, we are obligated to purchase Renewable Identification Numbers ("RINs"). In the first quarter of 2015, the cost of our RINs was $53 million (2014 – $26 million). This increase is consistent with the rise in the ethanol RINs benchmark price as well as the increase in refined product output. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2015 were labour, maintenance, utilities and supplies. Operating expenses decreased 11 percent primarily due to a reduction in planned maintenance and turnaround activities and a decline in utility costs resulting from a decrease in natural gas prices.

Refining and Marketing – Capital Investment

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Wood River Refinery	**27**	11
Borger Refinery	**17**	12
Marketing	**-**	-
	44	23

Capital expenditures in the first quarter of 2015 focused on the debottlenecking project at Wood River, in addition to capital maintenance, projects improving our refinery reliability and safety, and environmental initiatives. In the first quarter of 2014, we and our partner sanctioned the Wood River debottleneck project. We received permit approval in the first quarter of 2015 and planned start-up is anticipated in the second half of 2016.

In 2015, we expect to invest between $240 million and $260 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

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 of 2015, Refining and Marketing DD&A increased by $7 million primarily due to the change in the U.S./Canadian dollar 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 $145 million of unrealized losses (2014 – $26 million of unrealized gains). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing costs and research costs.

($ millions)	Three Months Ended March 31, 2015	2014
General and Administrative	**72**	109
Finance Costs	**121**	130
Interest Income	**(11)**	(2)
Foreign Exchange (Gain) Loss, Net	**515**	147
Research Costs	**7**	2
(Gain) Loss on Divestiture of Assets	**(16)**	-
Other (Income) Loss, Net	**-**	(1)
	688	385

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in the first quarter of 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased $37 million primarily due to lower employee long-term incentive costs consistent with the decline in our share price.

Finance Costs

Finance costs include interest expense on our long-term debt, short-term borrowings and U.S. dollar denominated Partnership Contribution Payable, as well as the unwinding of the discount on decommissioning liabilities. Finance costs decreased $9 million in the first quarter of 2015. The decrease was primarily due to lower interest incurred on the Partnership Contribution Payable which was repaid in the first quarter of 2014, partially offset by a weakening of the Canadian dollar relative to the U.S. dollar.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the first quarter was 5.2 percent (2014 – 5.1 percent).

Foreign Exchange

($ millions)	Three Months Ended March 31, 2015	2014
Unrealized Foreign Exchange (Gain) Loss	**523**	143
Realized Foreign Exchange (Gain) Loss	**(8)**	4
	515	147

The majority of unrealized foreign exchange losses stem from translation of our U.S. dollar denominated debt as a result of a weaker Canadian dollar at March 31, 2015. The Canadian dollar weakened by nine percent relative to the U.S. dollar from December 31, 2014 to March 31, 2015.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in the first quarter of 2015 was $21 million (2014 – $20 million).

Income Tax

($ millions)	Three Months Ended March 31, 2015	2014
Current Tax		
Canada	**(86)**	43
United States	**-**	32
Total Current Tax	**(86)**	75
Deferred Tax	**(27)**	36
	(113)	111
Effective Tax Rate	**14%**	31%

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for taxes is adequate. There are usually a number of tax matters under review and as a result income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

In the first quarter of 2015, current income tax decreased $161 million due to a decrease in Canadian and U.S. Operating Cash Flow. Deferred income tax declined $63 million due to decreased Canadian and U.S. income and unrealized risk management losses compared with a gain 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 statutory tax rate as it reflects higher U.S. tax rates, permanent differences, adjustments for changes in tax rates and other tax legislation, variations in the estimate of reserves and differences between the provision and the actual amounts subsequently reported on the tax returns.

The decrease in our effective tax rate when compared with the first quarter of 2014 is primarily due to an increase in non-deductible foreign exchange losses which reduced the income tax recovery.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended March 31,	
($ millions)	**2015**	2014
Net Cash From (Used In)		
Operating Activities	**275**	457
Investing Activities	**(643)**	(2,397)
Net Cash Provided (Used) Before Financing Activities	**(368)**	(1,940)
Financing Activities	**1,292**	246
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(3)**	57
Increase (Decrease) in Cash and Cash Equivalents	**921**	(1,637)

	March 31, 2015	December 31, 2014
Cash and Cash Equivalents	**1,804**	883

Operating Activities

Cash from operating activities was $182 million lower in the first quarter of 2015 mainly due to lower Cash Flow as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, working capital was $2,026 million at March 31, 2015 compared with $772 million at December 31, 2014. The change in working capital was primarily due to the proceeds received from the common share issuance. We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In the first quarter of 2015, cash used in investing activities was $643 million, a $1,754 million decrease from 2014, primarily due to the repayment of the US$1.4 billion Partnership Contribution Payable in March 2014.

Financing Activities

Cash provided by financing activities increased $1,046 million, primarily due to net proceeds from our common share issuance, partially offset by the net repayment of short-term borrowings. In the first quarter of 2015, we had a net repayment of short-term borrowings compared to a net issuance in 2014. In the quarter we issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion. We plan to use the net proceeds to partially fund our capital expenditure program for 2015 and for general corporate purposes.

In the first quarter, we paid dividends of $0.2662 per share or $222 million (2014 – $0.2662 per share or $202 million), of which $138 million was paid in cash with the remainder reinvested in common shares issued from treasury through our DRIP (2014 – $202 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Our long-term debt at March 31, 2015 was $5,973 million (December 31, 2014 – $5,458) with no principal payments due until October 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars has remained unchanged since August 2012. The $515 million increase in long-term debt is due to foreign exchange.

As at March 31, 2015, we were 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 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, management of our asset portfolio and other corporate and financial opportunities that may be available to us.

The following sources of liquidity are available at March 31, 2015:

($ millions)	Amount	Term
Cash and Cash Equivalents	**1,804**	**Not applicable**
Committed Credit Facility	**3,000**	**November 2018**
U.S. Base Shelf Prospectus (1)	**US$2,000**	**July 2016**
Canadian Base Shelf Prospectus (1)	**1,500**	**July 2016**

(1) Availability is subject to market conditions.

Committed Credit Facility

We have a $3.0 billion committed credit facility. As of March 31, 2015, no amounts were drawn on our committed credit facility.

We have a commercial paper program which, together with our committed credit facility, is used to manage our short-term cash requirements. We reserve undrawn capacity under our committed credit facility for amounts of outstanding commercial paper. As of March 31, 2015, there was no commercial paper outstanding.

U.S. and Canadian Base Shelf Prospectuses

As at March 31, 2015, no notes were issued under our U.S. or Canadian base shelf prospectuses.

Financial Metrics

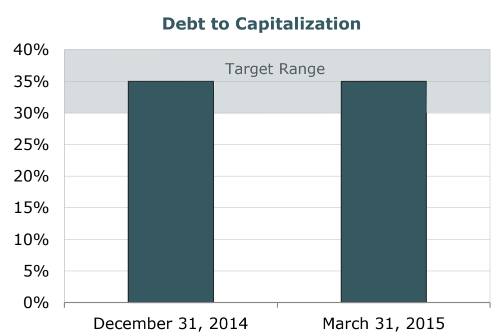
We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt.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

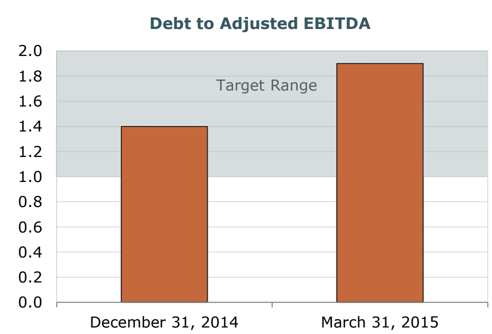
As at	March 31, 2015	December 31, 2014
Debt to Capitalization	**35%**	35%
Net Debt to Capitalization (1)	**27%**	31%
Debt to Adjusted EBITDA (times)	**1.9x**	1.4x
Net Debt to Adjusted EBITDA (times) (1)	**1.3x**	1.2x

(1) Net Debt is defined as Debt net of cash and cash equivalents.

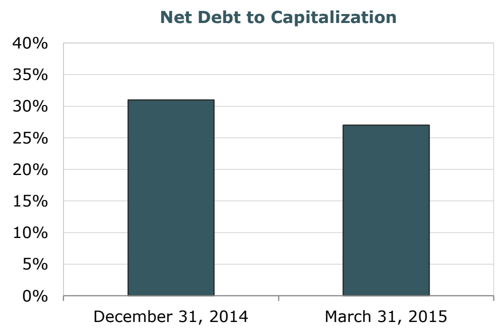
We continue to have long-term targets for a Debt to Capitalization ratio of between 30 to 40 percent and a Debt to Adjusted EBITDA of between 1.0 to 2.0 times. At March 31, 2015, our Debt to Capitalization and Debt to Adjusted EBITDA metrics are within our target ranges.

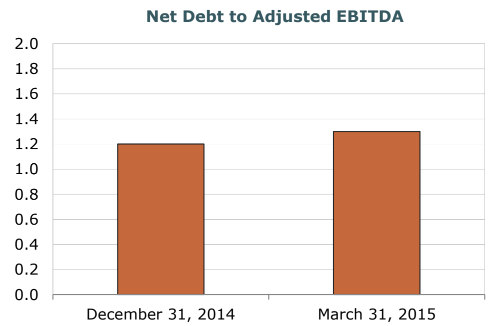
Debt to Capitalization remained consistent as higher debt balances, due to changes in foreign exchange consistent with the weakening of the Canadian dollar relative to the U.S. dollar, were offset by the increase in Shareholders' Equity as a result of the common share issuance. The increase in Debt to Adjusted EBITDA was due to higher debt balances as a result of foreign exchange and lower Adjusted EBITDA primarily due to a decline in Operating Cash Flow as a result of low commodity prices.





As at March 31, 2015, we held $1.8 billion in cash and cash equivalents. Net Debt to Capitalization and Net Debt to Adjusted EBIDTA were 27 percent and 1.3 times, respectively (December 31, 2014 – 31 percent and 1.2 times, respectively).





Additional information regarding our financial metrics and capital structure can be found in the notes to the Consolidated Financial Statements.

Outstanding Share Data and Stock-Based Compensation Plans

Cenovus is authorized to issue an unlimited number of common shares and, subject to certain conditions, an unlimited number of first preferred shares and an unlimited number of second preferred shares. At March 31, 2015, no preferred shares were outstanding. Cenovus issued 71.4 million common shares in the first quarter of 2015, including 67.5 million shares related to the common share issuance and 3.9 million shares issued under the DRIP.

The DRIP permits shareholders to reinvest their dividends into additional common shares. At the discretion of Cenovus, the additional common shares may be issued from treasury or purchased on the market. On February 12, 2015, we announced that the common shares issued to participants under our DRIP will be issued from treasury at a three percent discount to the average market price, as defined in the DRIP. Refer to cenovus.com for more details. For the first quarter dividend, the participation rate in the DRIP was approximately 37 percent and resulted in $81 million of cash savings.

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 our Stock Option Plan, Cenovus has a Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit Plans.

PSUs and RSUs 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 Note 27 of the Consolidated Financial Statements and Note 16 of our interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at March 31, 2015	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**828,533**	**N/A**
Stock Options	**48,015**	**27,206**
Other Stock-Based Compensation Plans	**8,443**	**1,376**

Contractual Obligations and Commitments

We have entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. 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 Consolidated Financial Statements.

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 2014 annual MD&A and AIF.

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 2014 annual MD&A has not changed substantially since December 31, 2014. In addition, no new material risks have been 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, 2014. 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 business 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 Note 19 to the interim Consolidated Financial Statements. The financial impact is summarized below:

Impact of Financial Risk Management Activities

	Three Months Ended March 31,					
	2015			2014		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(128)**	**119**	**(9)**	34	(26)	8
Natural Gas	**(12)**	**11**	**(1)**	-	1	1
Refining	**(14)**	**9**	**(5)**	(4)	(1)	(5)
Power	**3**	**6**	**9**	-	-	-
(Gain) Loss on Risk Management	**(151)**	**145**	**(6)**	30	(26)	4
Income Tax Expense (Recovery)	**40**	**(37)**	**3**	(7)	7	-
(Gain) Loss on Risk Management, After Tax	**(111)**	**108**	**(3)**	23	(19)	4

In the first quarter of 2015, management of commodity price risk resulted in realized gains on crude oil and natural gas financial instruments, consistent with our contract prices exceeding the average benchmark price. We recorded unrealized losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions.

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 2014 annual MD&A.

Management is 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, 2014.

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 recorded in our annual and interim Consolidated Financial Statements. There have been no changes to our critical judgments used in applying accounting policies in the first quarter of 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

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 recorded 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 2015. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2014.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the three months ended March 31, 2015.

Future Accounting Pronouncements

There were no new or amended accounting standards or interpretations issued during the three months ended March 31, 2015 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, 2014.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") in the three months ended March 31, 2015 that have materially affected, or are reasonably likely to materially affect, ICFR.

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

TRANSPARENCY AND CORPORATE RESPONSIBILITY

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

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

In February 2015, Cenovus was named the top Canadian company for Best Sustainability Practice at the Investor Relations Magazine Awards for the third consecutive year. In January 2015, Cenovus was included in the RobecoSAM Sustainability Yearbook for the second time in a row. RobecoSAM is a Swiss-based specialist in international sustainability investment that publishes the Dow Jones Sustainability Index ("DJSI"). Cenovus continues to be named to the DJSI family of indices and is currently listed on the DJSI World and DJSI North American Index.

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

OUTLOOK

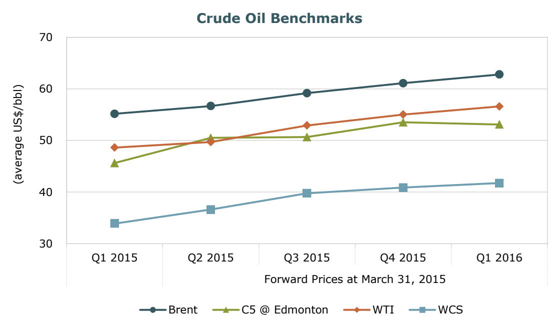
We expect 2015 to be a challenging time for our industry. Since December 2014, crude oil prices have remained significantly lower than prices in the first half of 2014 and we anticipate prices will remain relatively low throughout 2015. We revised our 2015 budget in January, reducing our capital spending plans and introducing other initiatives intended to conserve cash and maintain the strength of our balance sheet. We have strong producing assets, an integrated portfolio, a solid balance sheet and flexible capital plans, which should allow us to face the challenges in 2015. We continue to pursue our long-term strategy, though at a pace we believe is more in line with the current commodity price environment.

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

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

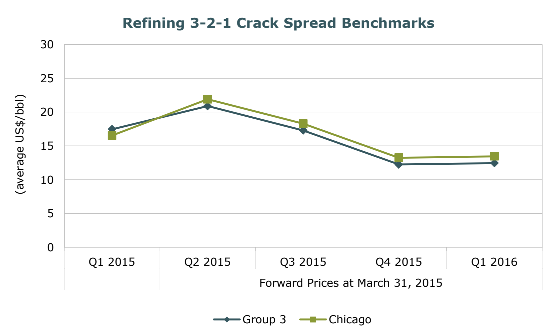
- We expect the general outlook for crude oil prices will be tied primarily to the non-OPEC supply response to the current price environment, the pace of growth of the global economy and the availability of storage for crude oil and refined products. Overall, we expect Brent crude oil prices to improve as the year progresses. However, there is some risk prices may fall in the second quarter due to seasonally weak demand in the spring and continued high levels of supply from OPEC. Going forward, a reduction in global supply growth, combined with annual increases in demand growth and seasonal improvements should slightly improve prices for the last half of the year. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The current low crude oil price environment also serves to help boost global economic momentum which, with the exception of the U.S., has been faced with mounting deflationary concerns and struggling emerging markets. Expectations have faded that OPEC may reduce production and provide some support to prices as OPEC has repeatedly placed the responsibility of supply correction on non-OPEC producers;
- We expect the Brent-WTI differential to be volatile as the uncertain pace of U.S. supply growth and its ability to displace imports will dictate price direction. In addition, the seasonality of crude oil demand, refinery turnarounds and high levels of U.S. crude oil in storage add to the volatility; and
- We expect the WTI-WCS differential to be volatile given Canadian supply growth and uncertainty around the timing of new rail infrastructure and incremental pipeline capacity.

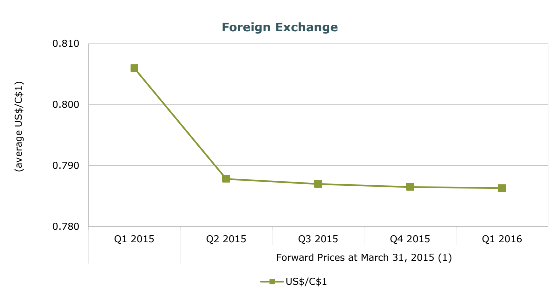


Average market crack spreads improved late in the first quarter of 2015 as a result of a number of unplanned refinery outages. For the next twelve months, we expect average market crack spreads to decline slightly as refinery utilization improves.

Natural gas prices are expected to remain weak throughout 2015. The inventory of drilled but uncompleted wells should keep supply growth strong even with a decline in industry activity. Coal-to-gas substitution in the power sector will be required to correct anticipated high storage levels before the winter season.

The average foreign exchange forward price over the next four quarters is US$0.787/C$. The Bank of Canada rate cut in the first quarter has acted to further decrease the Canadian dollar against the U.S. dollar. Timing of key interest rate decisions, both in Canada and the U.S., and U.S. economic momentum will dictate future foreign exchange fluctuations. Overall, we expect the Canadian dollar to remain relatively weak which will have a positive impact on our revenues and Operating Cash Flow.



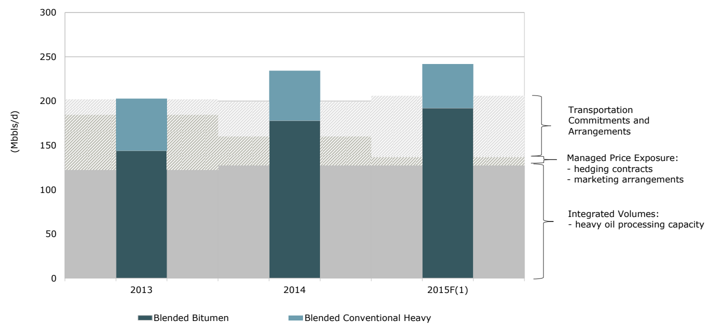


(1) Refer to the foreign exchange rate sensitivities found within our current guidance available at cenovus.com.

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

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

Protection Against Canadian Congestion



(1) Expected gross production capacity.

Key Priorities for 2015

Maintain Financial Resilience

We have strong producing assets, an integrated portfolio and a solid balance sheet which should position us well to face the challenges of 2015. Our capital planning process is flexible. Spending can be further reduced in response to declines in commodity prices and other economic factors, so that we should be able to maintain our financial strength and resilience and advance our strategy without compromising our future plans. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in 2015.

Attack Cost Structures

We continue to challenge 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 maximize the strengths of our business model. We have identified opportunities to achieve between $400 million and $500 million in anticipated annual operating and capital cost reductions in the years ahead.

As a result of the slowdown across the energy sector, we expect to see reductions in demand for labour, service and materials. This should create opportunities for us to make improvements in our cost structure.

Enable Market Access

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production. This includes continued support for proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 to 20 percent of our crude oil production to market by rail, assessing options to maximize the value of our oil by offering a wider range of products, including existing dilbit blends, under blended bitumen or dry bitumen, and potential expansions of our refining capacity as our production grows.

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

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", "future", "target", "project", "capacity", "could", "should", "focus", "goal", "outlook", "potential", "may", "strategy", "opportunity" or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future value or net asset value, projections for 2015 and future years, forecast operating and financial results, planned capital expenditures, including the timing and financing thereof, expected future production, including the timing, stability or growth thereof, expected future refining capacity, broadening market access, improving cost structures, dividend plans and strategy, including with respect to the dividend reinvestment plan, 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, future credit ratings and projected shareholder return. 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.

2015 guidance is based on an average diluted number of shares outstanding of approximately 760 million. It assumes: Brent of US$53.50/bbl, WTI of US$50.50/bbl; WCS of US$36.25/bbl; NYMEX of US$3.00/MMBtu; AECO of $2.70/GJ; Chicago 3-2-1 crack spread of US$11.75/bbl; and an exchange rate of $0.83 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: volatility of and assumptions regarding oil and natural gas prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; 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, generally, and on terms acceptable to us; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; 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 period ended March 31, 2015, available on SEDAR at sedar.com, EDGAR at 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.