MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED SEPTEMBER 30, 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 October 28, 2015, should be read in conjunction with our September 30, 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 October 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, Net 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 September 30, 2015, we had a market capitalization of approximately $17 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 nine months ended September 30, 2015 was approximately 209,000 barrels per day and our average natural gas production was 447 MMcf per day. Our refineries processed an average of 424,000 gross barrels per day of crude oil feedstock into an average of 448,000 gross barrels per day of refined products.

The low commodity price environment continued to significantly impact the oil and gas industry in the third quarter. After experiencing a modest improvement in average crude oil benchmark prices in the second quarter of 2015, average prices fell between 19 percent and 28 percent. Average crude oil prices were also 51 percent to 57 percent lower than in the third quarter of 2014. The significant decline and volatility in commodity prices has caused widespread reductions in capital spending programs and extensive efforts to reduce costs across the industry. We continue to focus on preserving our financial resilience, exercising capital discipline and achieving sustainable cost reductions as we anticipate crude oil prices will remain low for a prolonged period of time.

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.

We have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

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, 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 for 2015 to be between $1.8 billion and $1.9 billion. This is a significant reduction from 2014 levels in response to the continued low commodity price environment. We expect proceeds from our common share issuance in March 2015, the sale of our royalty interest and mineral fee title lands business in July 2015 and internally generated cash flow to fund our capital investment in 2015 and into the next years of our business plan. We remain well positioned to manage through these volatile times. To continue to help ensure our financial flexibility, we plan to prudently use our balance sheet capacity, manage our asset portfolio and consider other corporate and financial opportunities that may be available to us.

Dividend

In the third quarter of 2015, we paid a dividend of $0.16 per share, a decrease of 40 percent from our first and second quarter dividends of $0.2662 per share. The declaration of dividends is at the sole discretion of our Board and is considered each quarter.

In the first quarter of 2015, we initiated a temporary three percent discount under our dividend reinvestment plan ("DRIP") for shareholders who reinvested their dividends in common shares. While the DRIP continues to be in place, the discount has been discontinued as of July 2015.

Innovation and the Environment

Technology development, research activities and understanding our impact on the environment play increasingly larger roles in all aspects of our business. We continue to seek out new technologies and are actively developing our own technologies with the goal 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 footprint. 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:

	Nine Months Ended September 30, 2015		
	Ownership Interest (percent)	Net Production Volumes (bbls/d)	Gross Production Volumes (bbls/d)
Existing Projects			
Foster Creek	**50**	**65,906**	**131,812**
Christina Lake	**50**	**74,720**	**149,440**
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.

	Nine Months Ended September 30, 2015	
($ millions)	Crude Oil	Natural Gas
Operating Cash Flow	**853**	**7**
Capital Investment	**945**	**1**
Operating Cash Flow Net of Related Capital Investment	**(92)**	**6**

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.

($ millions)	Nine Months Ended September 30, 2015 Crude Oil [1]	Natural Gas
Operating Cash Flow	549	231
Capital Investment	148	9
Operating Cash Flow Net of Related Capital Investment	**401**	**222**

(1) *Includes NGLs.*

We have established crude oil and natural gas producing assets, including a carbon dioxide ("CO_2") enhanced oil recovery project in Weyburn, Saskatchewan, as well as heavy oil assets at Pelican Lake and developing tight oil assets, located in Alberta.

Refining and Marketing

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

	Nine Months Ended September 30, 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 crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

($ millions)	Nine Months Ended September 30, 2015
Operating Cash Flow	424
Capital Investment	159
Operating Cash Flow Net of Related Capital Investment	**265**

QUARTERLY OPERATING AND FINANCIAL HIGHLIGHTS

Challenges from the sustained low commodity price environment continued to significantly impact our industry in the third quarter of 2015. Average crude oil benchmark prices declined between 19 percent and 28 percent from the second quarter. Commodity prices are expected to stay low for the remainder of 2015 and throughout 2016. The forward price of Western Canadian Select ("WCS") for the fourth quarter as at September 30, 2015 is expected to average approximately US$32 per barrel. Maintaining financial resilience, capital spending discipline and conserving cash are extremely important in this low commodity price environment.

Cenovus remains well positioned to manage through these volatile times. We are focused on preserving our financial flexibility, exercising capital discipline and achieving sustainable cost reductions. In the third quarter, we:

- Completed the sale of our royalty interest and mineral fee title lands business, which included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. We received cash proceeds of approximately $3.3 billion. A royalty on Cenovus's working interest production on these fee lands and a Gross Overriding Royalty ("GORR") on production from our Pelican Lake and Weyburn assets were also included in the sale;
- Closed the purchase of a crude-by-rail terminal for $75 million, plus adjustments, to expand our portfolio of transportation options;
- Reduced our total crude oil operating costs by $53 million or $3.21 per barrel, compared with 2014;
- Continued to reduce our discretionary spending;
- Additional workforce reductions were identified in the third quarter and implemented in early October, resulting in a 24 percent reduction of our workforce in 2015; and
- Reduced our third quarter dividend to $0.16 per share in response to the low commodity price environment.

Operational Results

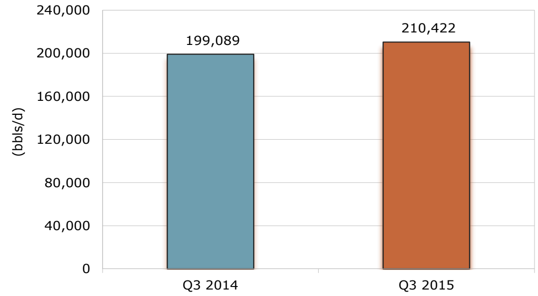
Our upstream assets continued to perform well in the third quarter. Total crude oil production averaged 210,422 barrels per day in the quarter.

Crude oil production from our Oil Sands segment averaged 146,743 barrels per day in the third quarter, an increase of 17 percent from the third quarter of 2014.

Production from Foster Creek averaged 71,414 barrels per day in the third quarter, an increase of 26 percent compared with 2014 due to the ramp-up of phase F, strong initial production after operations were temporarily shut down in the second quarter due to a nearby forest fire, and production from additional wells.

Average production at Christina Lake rose to 75,329 barrels per day, a 10 percent increase from the third quarter of 2014. The increase was due to production from additional wells, including wells using our Wedge Well™ technology and improved performance of our facilities.

Total Crude Oil Production Volumes



Our Conventional crude oil production averaged 63,679 barrels per day, a 14 percent decrease compared with 2014. An increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the sale of our royalty interest and mineral fee title lands business, and the divestiture of a non-core asset in 2014. Third party royalty interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day.

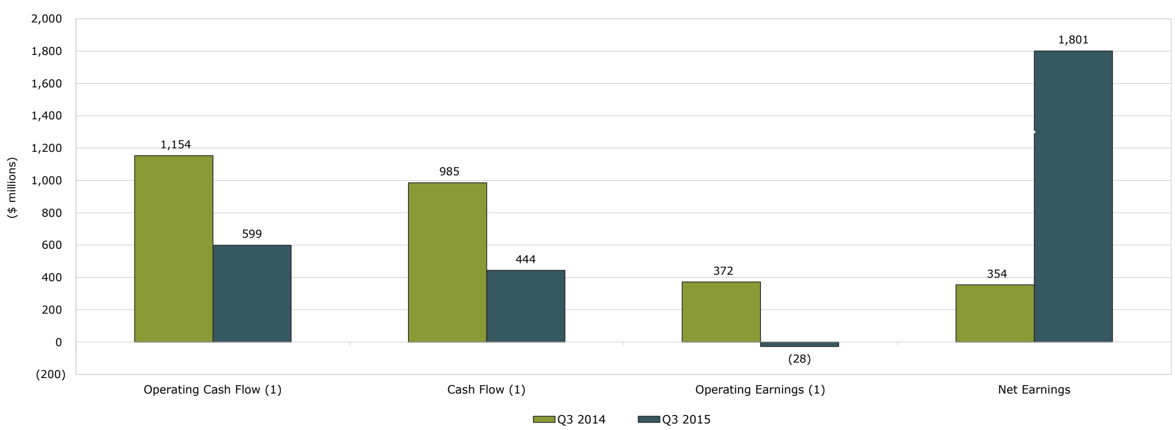
Crude oil processed and refined product output decreased slightly from 2014 due to unplanned outages and planned turnaround activities. We processed an average of 394,000 gross barrels per day (2014 – 407,000 gross barrels per day) of crude oil, of which 186,000 gross barrels per day (2014 – 201,000 gross barrels per day) was heavy crude oil. We produced 414,000 gross barrels per day of refined products, a three percent decrease from 2014.

We commenced operations of our crude-by-rail facility at Bruderheim, Alberta, and 12 unit trains, including five unit trains for third parties, were loaded in the first month of operations.

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.

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



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

Crude oil benchmark prices declined from the second quarter of 2015 and were significantly lower than in the third quarter of 2014. Low commodity prices continue to significantly impact our financial results.

Financial highlights for the third quarter of 2015 compared with 2014 include:

Operating Cash Flow

Operating Cash Flow decreased 48 percent to $599 million. Upstream Operating Cash Flow of $570 million (2014 – $1,086 million) declined primarily due to the low commodity price environment. The sale of our royalty interest and mineral fee title lands business reduced third quarter Operating Cash Flow by approximately $23 million.

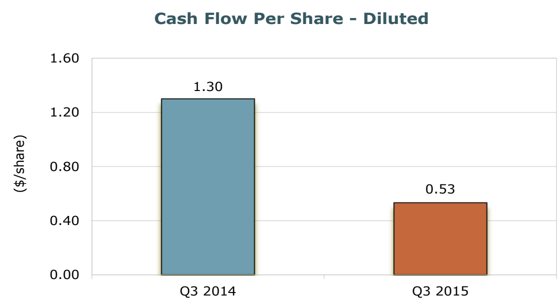
The decreases in upstream Operating Cash Flow were partially offset by:

- Realized risk management gains of $206 million compared with losses of $4 million in 2014;
- Lower royalties due to a decline in crude oil sales prices, partially offset by additional royalties resulting from the sale of our royalty interest and mineral fee title lands business; and
- A reduction in crude oil operating expenses of $3.21 per barrel to $11.39 per barrel, primarily related to lower fuel costs due to a decrease in natural gas prices, lower repairs and maintenance costs, and a decline in workforce costs.

Operating Cash Flow from our Refining and Marketing segment declined $39 million or 57 percent. The decrease resulted from higher heavy crude oil feedstock costs relative to the West Texas Intermediate ("WTI") benchmark price, higher operating costs and lower refined product output, partially offset by improved margins on the sale of secondary products such as coke and asphalt, an increase in average market crack spreads and weakening of the Canadian dollar relative to the U.S. dollar.

Cash Flow

Cash Flow decreased 55 percent to $444 million primarily due to the decline in Operating Cash Flow discussed above.



Operating Earnings (Loss)

Operating Earnings decreased $400 million to a loss of $28 million primarily due to lower Cash Flow, as discussed above, partially offset by a recovery of deferred income tax compared with an expense in 2014.

Net Earnings

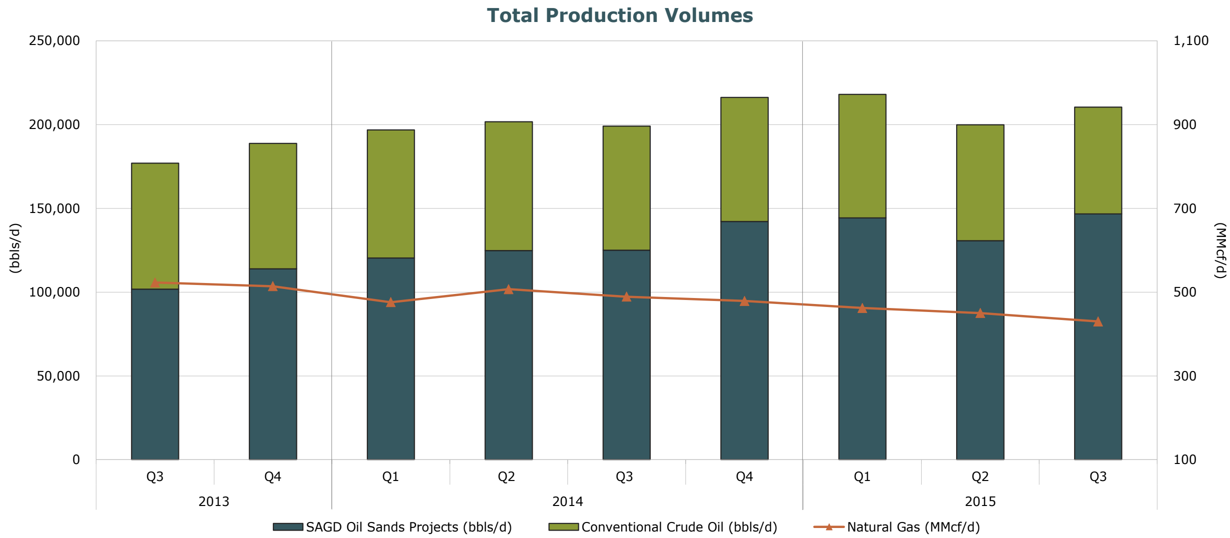
Net Earnings was $1,801 million compared with $354 million in 2014. Net Earnings increased due to an after-tax gain of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business, partially offset by lower Operating Earnings discussed above, an increase in non-operating unrealized foreign exchange losses, and lower unrealized risk management gains compared with 2014.

Capital Investment

We continue to pursue our long-term strategy, though at a pace we believe is more in line with the current commodity price environment, focusing on capital discipline 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.

Capital investment in the quarter was $400 million, a decrease of 47 percent. We continued to focus on sustaining existing oil sands production, and completing the Foster Creek phase G expansion and Christina Lake phase F expansion.

OPERATING RESULTS



Crude Oil Production Volumes

(barrels per day)	Three Months Ended September 30, 2015	Percent Change	2014	Nine Months Ended September 30, 2015	Percent Change	2014
Oil Sands						
Foster Creek	**71,414**	**26%**	56,631	**65,906**	**18%**	56,070
Christina Lake	**75,329**	**10%**	68,458	**74,720**	**11%**	67,400
	146,743	**17%**	125,089	**140,626**	**14%**	123,470
Conventional						
Heavy Oil	**33,997**	**(13)%**	39,096	**35,739**	**(11)%**	40,060
Light and Medium Oil	**28,491**	**(15)%**	33,548	**31,787**	**(8)%**	34,488
NGLs [(1)]	**1,191**	**(12)%**	1,356	**1,286**	**7%**	1,200
	63,679	**(14)%**	74,000	**68,812**	**(9)%**	75,748
Total Crude Oil Production	**210,422**	**6%**	199,089	**209,438**	**5%**	199,218

(1) NGLs include condensate volumes.

Foster Creek production increased in the three and nine months ended September 30, 2015, primarily due to the ramp-up of phase F, strong initial production after operations were temporarily shut down in the second quarter due to a nearby forest fire, and production from additional wells. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. On a year-to-date basis, production increases were partially offset when production at Foster Creek was shut down for 11 full days as a safety precaution due to a nearby forest fire. The forest fire decreased production by approximately 3,500 barrels per day on a year-to-date basis.

Production from Christina Lake increased in the third quarter and on a year-to-date basis due to production from additional wells, including wells using our Wedge Well™ technology, and improved performance of our facilities.

Our Conventional crude oil production in the three and nine months ended September 30, 2015 decreased from 2014. An increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production from these divested assets was 1,251 barrels per day in the third quarter (2014 – 6,947 barrels per day) and 3,417 barrels per day on a year-to-date basis (2014 – 7,293 barrels per day).

Natural Gas Production Volumes

(MMcf per day)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Conventional	**411**	466	**427**	469
Oil Sands	**19**	23	**20**	22
	430	489	**447**	491

In the three and nine months ended September 30, 2015, our natural gas production declined 12 percent and nine percent, respectively. Production decreased primarily due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 6 MMcf per day and 13 MMcf per day in the three and nine months ended September 30, 2015, respectively (2014 – 20 MMcf per day and 20 MMcf per day).

Operating Netbacks

	Three Months Ended September 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)		Nine Months Ended September 30, Crude Oil [1] ($/bbl)		Natural Gas ($/Mcf)	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014
Price [2]	**34.03**	76.57	**3.00**	4.22	**37.90**	77.04	**2.96**	4.52
Royalties	**1.60**	6.52	**0.11**	0.08	**1.85**	6.56	**0.06**	0.08
Transportation and Blending [2]	**5.61**	3.08	**0.10**	0.11	**5.39**	2.96	**0.11**	0.11
Operating Expenses	**11.39**	14.60	**1.16**	1.24	**12.23**	16.41	**1.19**	1.24
Production and Mineral Taxes	**0.23**	0.54	**0.01**	0.05	**0.25**	0.52	**0.01**	0.06
Netback Excluding Realized Risk Management	**15.20**	51.83	**1.62**	2.74	**18.18**	50.59	**1.59**	3.03
Realized Risk Management Gain (Loss)	**10.07**	(0.45)	**0.37**	0.11	**6.25**	(1.78)	**0.35**	0.03
Netback Including Realized Risk Management	**25.27**	51.38	**1.99**	2.85	**24.43**	48.81	**1.94**	3.06

(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 $19.18 per barrel for the third quarter (2014 – $28.48 per barrel) and in the nine months ended September 30, 2015 was $21.32 per barrel (2014 – $31.92 per barrel).

Our average crude oil netback in the three and nine months ended September 30, 2015, excluding realized risk management gains and losses, decreased $36.63 per barrel and $32.41 per barrel, respectively, compared with 2014. The declines primarily resulted from lower sales prices, consistent with the decline in benchmark prices, partially offset by weakening of the Canadian dollar relative to the U.S. dollar, a decline in royalties and lower operating costs. The weakening of the Canadian dollar, on a year-to-date basis, compared with 2014 had a positive impact on our crude oil price of approximately $4.98 per barrel. Royalties declined due to lower crude oil sales prices.

In 2015, our average natural gas netback, excluding realized risk management gains and losses, decreased primarily due to lower sales prices consistent with the decline in the AECO benchmark price.

Refining [1]

	Three Months Ended September 30, 2015	Percent Change	2014	Nine Months Ended September 30, 2015	Percent Change	2014
Crude Oil Runs (Mbbls/d)	**394**	**(3)%**	407	**424**	**-**	424
Heavy Crude Oil	**186**	**(7)%**	201	**202**	**(1)%**	205
Refined Product (Mbbls/d)	**414**	**(3)%**	429	**448**	**-**	446
Crude Utilization (percent)	**86**	**(2)%**	88	**92**	**-**	92

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

In the third quarter, unplanned process unit outages at our Borger refinery for most of July and the start of a planned turnaround at Wood River reduced crude oil runs and refined product output. The Wood River turnaround is expected to be completed in October. In the third quarter of 2014, we had an unplanned coker outage at Borger that lasted approximately two weeks and a planned turnaround at Wood River.

On a year-to-date basis, crude oil runs and refined product output remained consistent. The unplanned outages at Borger and planned turnarounds at both of our refineries in 2015 had a similar impact on crude oil runs and refined product output as the outage and turnarounds in 2014.

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)

	Nine Months Ended September 30,					
	2015	**Percent Change**	2014	**Q3 2015**	Q2 2015	Q3 2014
Crude Oil Prices (US$/bbl)						
Brent						
Average	**56.61**	**(47)%**	107.02	**51.17**	63.50	103.39
End of Period	**48.37**	**(49)%**	94.67	**48.37**	63.59	94.67
WTI						
Average	**51.00**	**(49)%**	99.61	**46.43**	57.94	97.17
End of Period	**45.09**	**(51)%**	91.16	**45.09**	59.47	91.16
Average Differential Brent-WTI	**5.61**	**(24)%**	7.41	**4.74**	5.56	6.22
WCS (2)						
Average	**37.80**	**(52)%**	78.49	**33.16**	46.35	76.99
End of Period	**31.62**	**(58)%**	75.84	**31.62**	48.14	75.84
Average Differential WTI-WCS	**13.20**	**(38)%**	21.12	**13.27**	11.59	20.18
Condensate (C5 @ Edmonton)						
Average	**49.25**	**(51)%**	100.41	**44.21**	57.94	93.45
Average Differential WTI-Condensate (Premium)/Discount	**1.75**	**(319)%**	(0.80)	**2.22**	-	3.72
Average Differential WCS-Condensate (Premium)/Discount	**(11.45)**	**(48)%**	(21.92)	**(11.05)**	(11.59)	(16.46)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**71.82**	**(38)%**	116.11	**73.05**	79.96	113.30
Chicago Ultra-low Sulphur Diesel ("ULSD")	**71.09**	**(42)%**	122.91	**67.02**	75.92	118.56
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	**20.66**	**11%**	18.61	**24.67**	20.77	17.57
Group 3	**19.61**	**14%**	17.27	**22.03**	19.34	16.65
Average Natural Gas Prices						
AECO (C$/Mcf)	**2.81**	**(38)%**	4.55	**2.80**	2.67	4.22
NYMEX (US$/Mcf)	**2.80**	**(39)%**	4.56	**2.77**	2.64	4.06
Basis Differential NYMEX-AECO (US$/Mcf)	**0.56**	**44%**	0.39	**0.61**	0.50	0.16
Foreign Exchange Rates (US$ per C$1)						
Average	**0.794**	**(13)%**	0.914	**0.764**	0.813	0.918

(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 third quarter was $43.40 per barrel (2014 – $83.87 per barrel) and for the nine months ended September 30, 2015 was $47.61 per barrel (2014 – $85.88 per barrel).

Crude Oil Benchmarks

Crude oil benchmark prices in the third quarter declined from the second quarter and were significantly lower than in 2014. The average Brent, WTI and WCS benchmark prices continued to be impacted by a global imbalance of supply and demand which began in the last half of 2014. This global imbalance was created by weak global demand and strong growth in North American crude oil supply which was further amplified by the sustained decision of the Organization of Petroleum Exporting Countries ("OPEC") to maintain its level of crude oil output and discontinue its role as the swing supplier of crude oil. Despite significantly lower crude oil prices in 2015, the global imbalance has only slightly improved. After a slight increase in crude oil prices in the second quarter of 2015, economic uncertainty in China and strong production from Saudi Arabia and Iraq have caused prices to fall.

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 three and nine months ended September 30, 2015, the average price of Brent crude oil decreased compared with 2014. The decline was due to the global supply and demand imbalance discussed above.

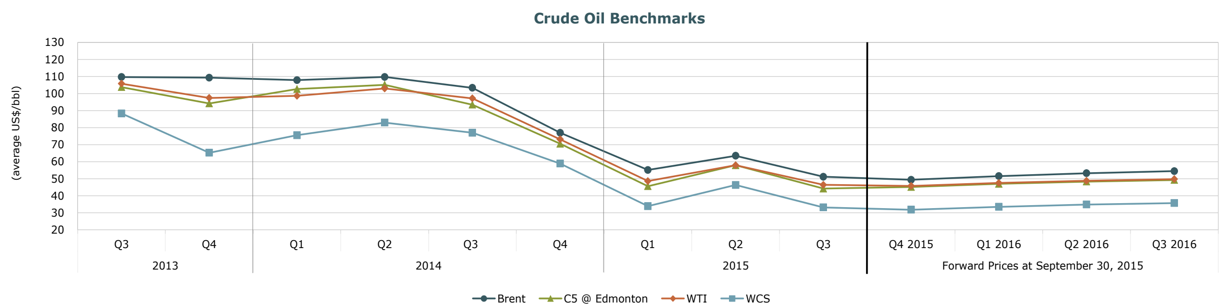
WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. The average Brent-WTI differential narrowed in the third quarter and on a year-to-date basis compared with 2014. WTI benchmark prices strengthened relative to Brent as a result of declining U.S. supply, high global crude oil inventory levels and continued strong demand in the U.S., leaving transportation costs as the primary driver of the Brent-WTI differential.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed by US$6.91 per barrel in the third quarter of 2015 and by US$7.92 per barrel on a year-to-date basis compared with 2014. The narrower differential resulted primarily from increased demand for WCS due to new pipeline infrastructure to the U.S. Gulf Coast, growing rail capacity and the slow return of heavy crude oil supply forced offline due to forest fires in northeastern Alberta during the second quarter of 2015. Late in the third quarter, Canadian crude oil supply was close to levels experienced prior to the fires, causing the WTI-WCS differential to widen compared with the second quarter.

Blending condensate with bitumen and heavy oil enables our 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. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the value attributed to transporting the condensate to Edmonton.

In the third quarter of 2015, the average WTI-Condensate differential decreased by US$1.50 per barrel compared with 2014. On a year-to-date basis, the differential changed by US$2.55 per barrel, with condensate being sold at a discount to WTI in 2015 as compared with being sold at a premium in 2014. This change was primarily due to new diluent pipeline infrastructure into Alberta and condensate supply growth.

The average WCS-Condensate differential narrowed by US$5.41 per barrel in the third quarter and US$10.47 per barrel on a year-to-date basis compared with 2014 due to condensate supply growth as well as improved diluent transportation infrastructure for condensate imports into Alberta and heavy oil exports to market.



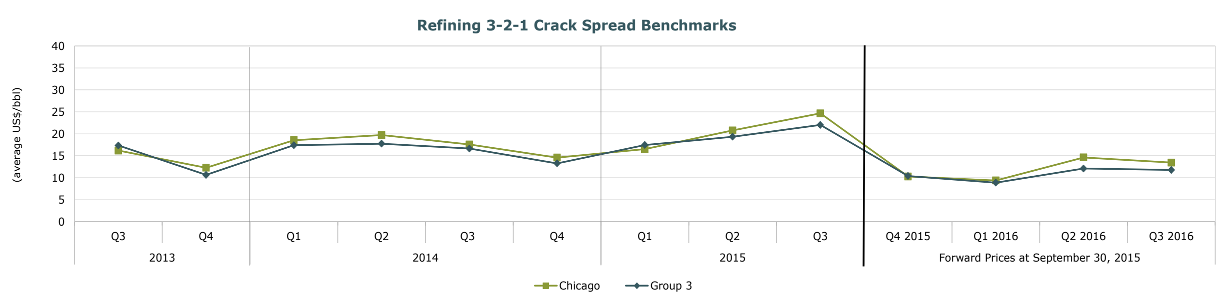
Refining Benchmarks

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 in the third quarter and on a year-to-date basis from 2014 due to weaker global crude oil pricing.

Average Chicago 3-2-1 crack spreads increased in the third quarter compared with 2014 as a major unplanned refinery outage in August 2015 caused product inventory drawdowns during the driving season. On a year-to-date basis, Chicago 3-2-1 crack spreads were higher driven by stronger product demand. Average Group 3 crack spreads increased in the third quarter and on a year-to-date basis as the unplanned refinery outage, as discussed above, 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 third quarter of 2015 and on a year-to-date basis primarily due to an increase in supply from the U.S. and Canada.

Foreign Exchange Benchmarks

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 third quarter and on a year-to-date basis compared with 2014, the Canadian dollar weakened relative to the U.S. dollar by $0.15 and $0.12, respectively, due to Canadian political and economic uncertainty, strengthening of the U.S. economy and lower commodity prices. The weakening of the Canadian dollar for the nine months ended September 30, 2015 compared with 2014, had a positive impact of approximately $1,329 million on our revenues and also resulted in an increase of $852 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)	Nine Months Ended September 30, 2015	Nine Months Ended September 30, 2014	2015 Q3	2015 Q2	2015 Q1	2014 Q4	2014 Q3	2014 Q2	2014 Q1	2013 Q4	2013 Q3
Revenues	**10,140**	15,404	**3,273**	3,726	3,141	4,238	4,970	5,422	5,012	4,747	5,075
Operating Cash Flow [(1)]	**2,076**	3,619	**599**	928	549	539	1,154	1,296	1,169	976	1,153
Cash Flow [(1)]	**1,416**	3,078	**444**	477	495	401	985	1,189	904	835	932
Per Share – Diluted	**1.74**	4.06	**0.53**	0.58	0.64	0.53	1.30	1.57	1.19	1.10	1.23
Operating Earnings (Loss) [(1)]	**35**	1,223	**(28)**	151	(88)	(590)	372	473	378	212	313
Per Share – Diluted	**0.04**	1.61	**(0.03)**	0.18	(0.11)	(0.78)	0.49	0.62	0.50	0.28	0.41
Net Earnings (Loss)	**1,259**	1,216	**1,801**	126	(668)	(472)	354	615	247	(58)	370
Per Share – Basic	**1.55**	1.61	**2.16**	0.15	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49
Per Share – Diluted	**1.55**	1.60	**2.16**	0.15	(0.86)	(0.62)	0.47	0.81	0.33	(0.08)	0.49
Capital Investment [(2)]	**1,286**	2,265	**400**	357	529	786	750	686	829	898	743
Dividends											
Cash Dividends	**396**	604	**133**	125	138	201	201	201	202	183	182
In Shares from Treasury	**182**	-	**-**	98	84	-	-	-	-	-	-
Per Share	**0.6924**	0.7986	**0.16**	0.2662	0.2662	0.2662	0.2662	0.2662	0.2662	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 third quarter, revenues decreased $1,697 million compared with 2014. On a year-to-date basis, revenues decreased $5,264 million compared with 2014.

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2014	**4,970**	**15,404**
Increase (Decrease) due to:		
Oil Sands	**(532)**	**(1,438)**
Conventional	**(374)**	**(1,112)**
Refining and Marketing	**(902)**	**(3,110)**
Corporate and Eliminations	**111**	**396**
Revenues for the Periods Ended September 30, 2015	**3,273**	**10,140**

Upstream revenues declined in the third quarter and on a year-to-date basis by 45 percent and 41 percent, respectively. Revenues decreased due to lower crude oil blend and natural gas sales prices, partially offset by higher crude oil sales volumes, weakening of the Canadian dollar relative to the U.S. dollar and lower royalties. The sale of our royalty interest and mineral fee title lands business also reduced revenues.

Revenues from our Refining and Marketing segment in the three and nine months ended September 30, 2015 decreased 29 percent and 31 percent, respectively. Refining revenues declined due to the decrease in refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. Refining revenues in the third quarter were also impacted by lower refined product output compared with 2014. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in the three and nine months ended September 30, 2015 decreased 40 percent and 37 percent from 2014, primarily due to a decline in 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.

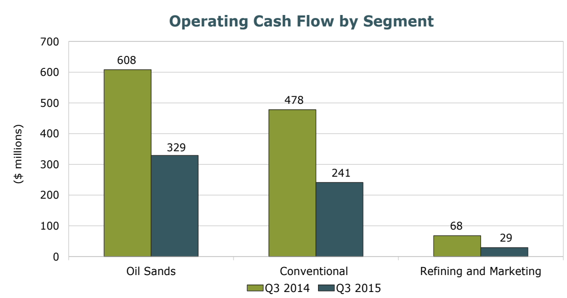
Further information regarding our revenues can be found in the Reportable Segments section of this MD&A.

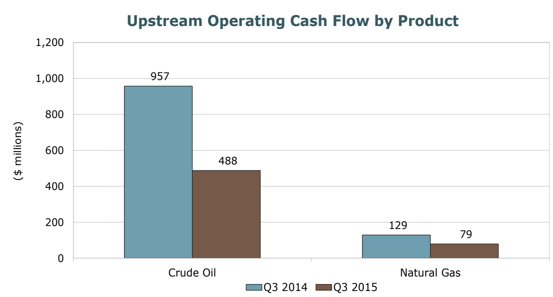
Operating Cash Flow

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 periods. 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 September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Revenues	**3,359**	5,167	**10,400**	16,060
(Add) Deduct:				
Purchased Product	**2,012**	2,918	**5,826**	8,836
Transportation and Blending	**483**	592	**1,509**	1,900
Operating Expenses	**480**	491	**1,390**	1,584
Production and Mineral Taxes	**5**	12	**16**	36
Realized (Gain) Loss on Risk Management Activities	**(220)**	-	**(417)**	85
Operating Cash Flow	**599**	1,154	**2,076**	3,619

Three Months Ended September 30, 2015 Compared With September 30, 2014





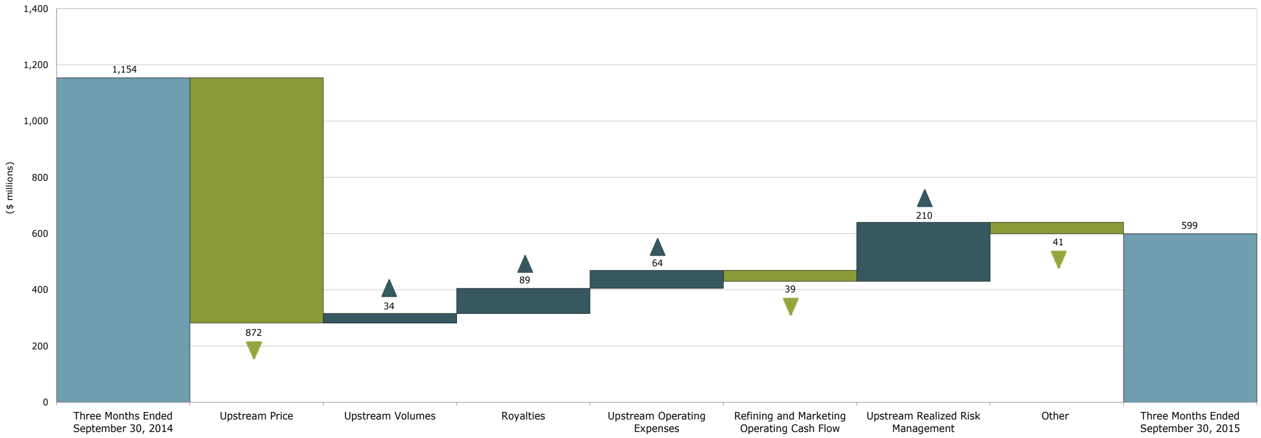
Operating Cash Flow declined 48 percent in the third quarter compared with 2014 primarily due to:

- A 56 percent decrease in our average crude oil sales price and a 29 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of higher heavy crude oil feedstock costs relative to the WTI benchmark price, higher operating costs and lower refined product output, partially offset by improved margins on the sale of secondary products, an increase in average market crack spreads and weakening of the Canadian dollar relative to the U.S. dollar; and
- A 12 percent decline in our natural gas sales volumes.

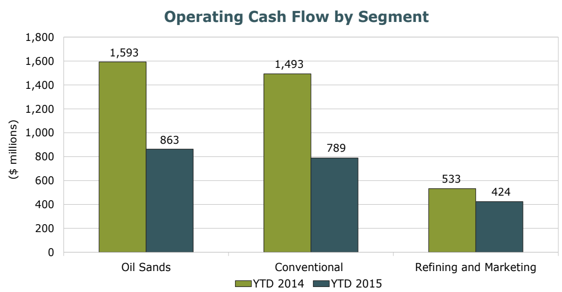
These declines to Operating Cash Flow were partially offset by:

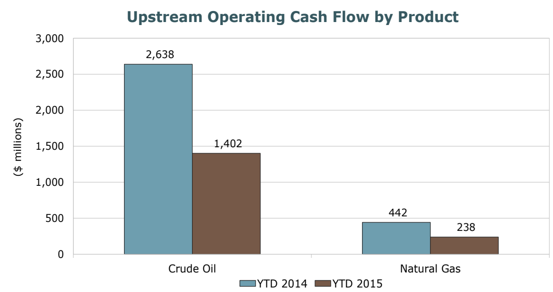
- Realized risk management gains of $206 million, excluding Refining and Marketing, compared with losses of $4 million in 2014;
- Lower royalties primarily due to a decline in crude oil sales prices;
- A reduction of $3.21 per barrel in crude oil operating expenses primarily related to lower fuel costs due to a decrease in natural gas prices, lower repairs and maintenance costs, and a decline in workforce costs; and
- A four percent increase in our crude oil sales volumes.

Operating Cash Flow Variance



Nine Months Ended September 30, 2015 Compared With September 30, 2014





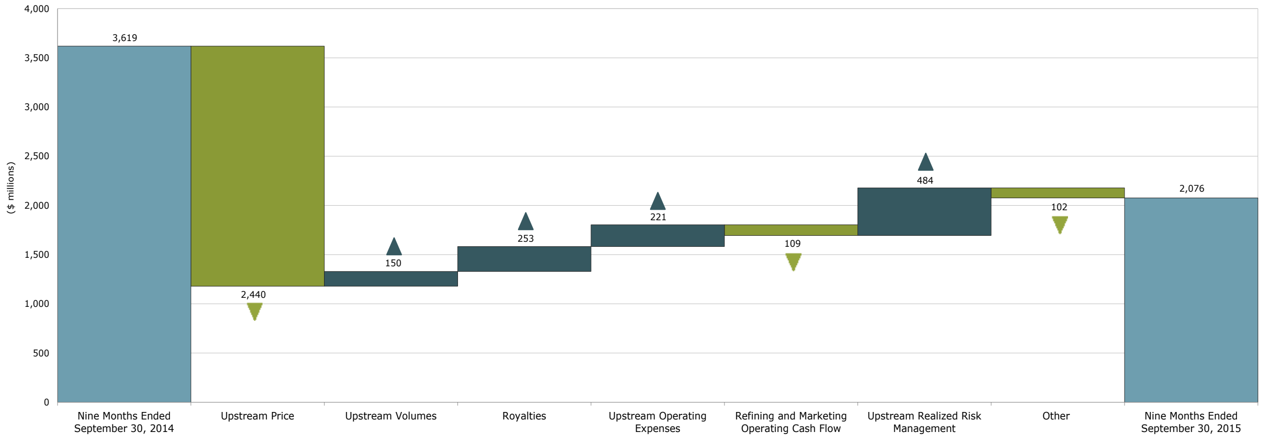
Operating Cash Flow declined 43 percent for the nine months ended September 30, 2015 primarily due to:

- A 51 percent decrease in our average crude oil sales price and a 35 percent decrease in our average natural gas sales price, consistent with lower associated benchmark prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of higher heavy crude oil feedstock costs relative to the WTI benchmark price and higher operating costs, partially offset by improved margins on the sale of secondary products and weakening of the Canadian dollar relative to the U.S. dollar; and
- A nine percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- Realized risk management gains of $390 million, excluding Refining and Marketing, compared with losses of $94 million in 2014;
- Lower royalties primarily due to a decrease in crude oil sales prices;
- A decrease of $4.18 per barrel in crude oil operating expenses primarily due to a decline in workover activities, a reduction in fuel costs due to lower natural gas prices, and lower repairs and maintenance costs; and
- A five percent increase in our crude oil sales volumes.

Operating Cash Flow Variance



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

Cash Flow

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash From Operating Activities	**542**	1,092	**1,152**	2,658
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(13)**	(28)	**(81)**	(97)
Net Change in Non-Cash Working Capital	**111**	135	**(183)**	(323)
Cash Flow	**444**	985	**1,416**	3,078

In the three and nine months ended September 30, 2015, Cash Flow decreased $541 million and $1,662 million, respectively, due to lower Operating Cash Flow, as discussed above, and higher current income tax. On a year-to-date basis, current income tax rose due to the acceleration in timing of income tax payable in response to the Alberta corporate tax rate increase.

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, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Earnings, Before Income Tax	**2,020**	533	**1,419**	1,715
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**(127)**	(165)	**169**	(180)
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**437**	253	**852**	272
(Gain) Loss on Divestiture of Assets	**(2,379)**	(137)	**(2,395)**	(157)
Operating Earnings (Loss), Before Income Tax	**(49)**	484	**45**	1,650
Income Tax Expense (Recovery)	**(21)**	112	**10**	427
Operating Earnings (Loss)	**(28)**	372	**35**	1,223

(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.

Operating Earnings decreased $400 million in the third quarter of 2015, primarily due to lower Cash Flow, as discussed above, partially offset by a recovery of deferred income tax compared with an expense in 2014.

On a year-to-date basis, Operating Earnings decreased $1,188 million, primarily due to:

- A decrease in Cash Flow, as discussed above;
- Unrealized foreign exchange losses of $26 million related to operating items, as compared with gains of $51 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 deferred income tax compared with an expense in 2014, and a recovery of employee long-term incentive costs compared with an expense in 2014.

Net Earnings

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings for the Periods Ended September 30, 2014	**354**	**1,216**
Increase (Decrease) due to:		
Operating Cash Flow [(1)]	**(555)**	**(1,543)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(38)**	**(349)**
Unrealized Foreign Exchange Gain (Loss)	**(198)**	**(657)**
Gain (Loss) on Divestiture of Assets	**2,242**	**2,238**
Expenses [(2)]	**34**	**75**
Depreciation, Depletion and Amortization	**2**	**(40)**
Exploration Expense	**-**	**(20)**
Income Tax Expense	**(40)**	**339**
Net Earnings for the Periods Ended September 30, 2015	**1,801**	**1,259**

(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 in the third quarter of 2015 increased $1,447 million and $43 million on a year-to-date basis primarily due to an after-tax gain of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business, and a deferred tax recovery related to non-operating items compared with an expense in 2014.

This increase was partially offset by:

- A decline in Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange losses of $437 million in the quarter and $852 million on a year-to-date basis (2014 – unrealized losses of $253 million and $272 million, respectively); and
- Unrealized risk management gains of $127 million in the quarter and unrealized risk management losses of $169 million on a year-to-date basis (2014 – unrealized gains of $165 million and $180 million, respectively).

Net Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Oil Sands	**272**	494	**946**	1,492
Conventional	**55**	198	**157**	621
Refining and Marketing	**67**	42	**159**	111
Corporate and Eliminations	**6**	16	**24**	41
Capital Investment	**400**	750	**1,286**	2,265
Acquisitions	**84**	-	**84**	17
Divestitures	**(3,329)**	(235)	**(3,345)**	(276)
Net Capital Investment [(1)]	**(2,845)**	515	**(1,975)**	2,006

(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 current commodity price environment, with a focus on capital discipline 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 expected from an extended period of low commodity prices and market volatility.

Capital investment in the three and nine months ended September 30, 2015 declined 47 percent and 43 percent, respectively. 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 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 2015, Oil Sands capital investment focused primarily on sustaining capital related to existing production, the 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 in the nine months ended September 30, 2015, 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 enhanced oil recovery project at Weyburn and drilling activity at our tight oil projects in southeast Alberta.

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:

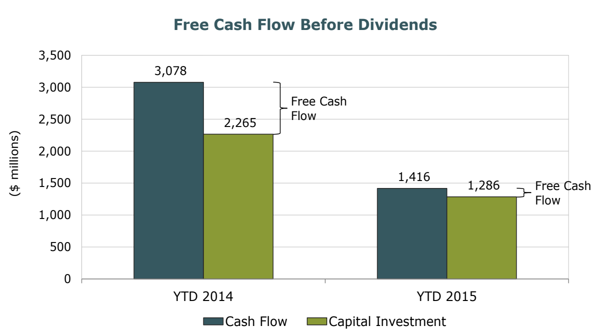
- First, to capital for our existing business operations;
- Second, to paying a dividend as part of providing strong total shareholder return; and
- Third, for growth or discretionary capital.

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.

We expect our total annual capital investment for 2015 to be between $1.8 billion and $1.9 billion, significantly below prior years in light of the commodity price environment. 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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Cash Flow [1]	**444**	985	**1,416**	3,078
Capital Investment (Committed and Growth)	**400**	750	**1,286**	2,265
Free Cash Flow [2]	**44**	235	**130**	813
Cash Dividends	**133**	201	**396**	604
	(89)	34	**(266)**	209

(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.



We expect our capital investment for the remainder of 2015 and the next years of our business plan to be funded from internally generated cash flow, proceeds from our common share issuance in March 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015. These transactions strengthen our balance sheet and provide us with greater resiliency to consider investing in opportunities that we believe have strong future returns. 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 September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Oil Sands	**749**	1,281	**2,353**	3,791
Conventional	**368**	742	**1,272**	2,384
Refining and Marketing	**2,242**	3,144	**6,775**	9,885
Corporate and Eliminations	**(86)**	(197)	**(260)**	(656)
	3,273	4,970	**10,140**	15,404

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 third quarter of 2015 compared with 2014 include:

- Production at Foster Creek increasing 26 percent, to an average of 71,414 barrels per day primarily as a result of phase F coming on stream, strong initial production after operations were temporarily shut down in the second quarter due to a nearby forest fire, and production from additional wells; and
- Christina Lake production increasing 10 percent, to an average of 75,329 barrels per day primarily due to production from additional wells, including wells using our Wedge Well™ technology, and improved performance of our facilities; and
- Reduced our crude oil operating costs by $19 million or $2.86 per barrel, compared with 2014.

Oil Sands – Crude Oil

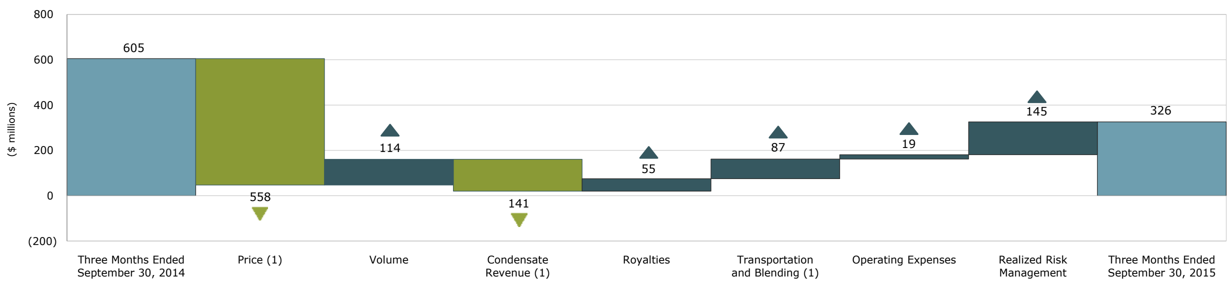
Three Months Ended September 30, 2015 Compared With September 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted)	Three Months Ended September 30, 2015	$ per-unit (1)	Three Months Ended September 30, 2014	$ per-unit (1)
Gross Sales	**749**	56	1,334	112
Less: Royalties	**7**	1	62	5
Revenues	**742**	55	1,272	107
Expenses				
Transportation and Blending	**431**	32	518	44
Operating	**128**	10	147	12
(Gain) Loss on Risk Management	**(143)**	(11)	2	-
Operating Cash Flow	**326**	24	605	51
Capital Investment	**272**		493	
Operating Cash Flow Net of Related Capital Investment	**54**		112	

(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

In the third quarter, our average crude oil sales price was $30.35 per barrel, a 33 percent decline from the second quarter and 58 percent lower than the third quarter of 2014. The prices we receive continue to be adversely 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 weakening of the Canadian dollar relative to the U.S. dollar and increased sales into the U.S. market that secure a higher sales price. The WCS-CDB differential narrowed to a discount of US$3.00 per barrel (2014 – a discount of US$3.91 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the third quarter, 84 percent of our Christina Lake production was sold as CDB (2014 – 90 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Three Months Ended September 30, 2015	Percent Change	2014
Foster Creek	**71,414**	**26%**	56,631
Christina Lake	**75,329**	**10%**	68,458
	146,743	**17%**	125,089

Foster Creek production increased primarily due to the ramp-up of phase F, strong initial production after operations were temporarily shut down in the second quarter due to a nearby forest fire, and production from additional wells. The ramp-up of phase F, our eleventh oil sands phase, is expected to take approximately eighteen months from start-up, which occurred in the third quarter of 2014. Strong initial production following the forest fire has subsided and production rates have returned to levels prior to the forest fire.

Production from Christina Lake increased in the third quarter due to production from additional wells, including wells using our Wedge Well™ technology, and improved performance of our facilities.

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 September 30, 2015	2014
Foster Creek	**0.8**	7.2
Christina Lake	**3.7**	7.9

Royalties decreased $55 million in the third quarter compared with 2014, primarily due to the decline in crude oil sales prices, partially offset by an increase in sales volumes. Foster Creek royalties were based on gross revenues in 2015 as compared with a calculation based on net profits in 2014. The further decline in WTI in the third quarter caused the annual calculation to change from a net profits basis to a gross revenues basis, resulting in a significant decrease in the royalty rate at Foster Creek. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $87 million or 17 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 transportation cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $54 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 added capacity on the Flanagan South system which increases our sales opportunities into the U.S. market with the expectation of achieving higher sales prices. 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.

Transportation costs also increased as lower volumes transported by rail were more than offset by new lease costs for rail cars, and higher loading fees and storage costs. Overall, in the third quarter of 2015, we moved an average of 6,642 gross barrels per day of crude oil by rail, consisting of 10 unit train shipments (2014 – 11,186 gross barrels per day, 18 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 third quarter of 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $19 million or $2.86 per barrel, primarily as a result of higher production, lower natural gas prices reducing fuel costs, and a decline in workforce costs.

Per-unit Operating Expenses

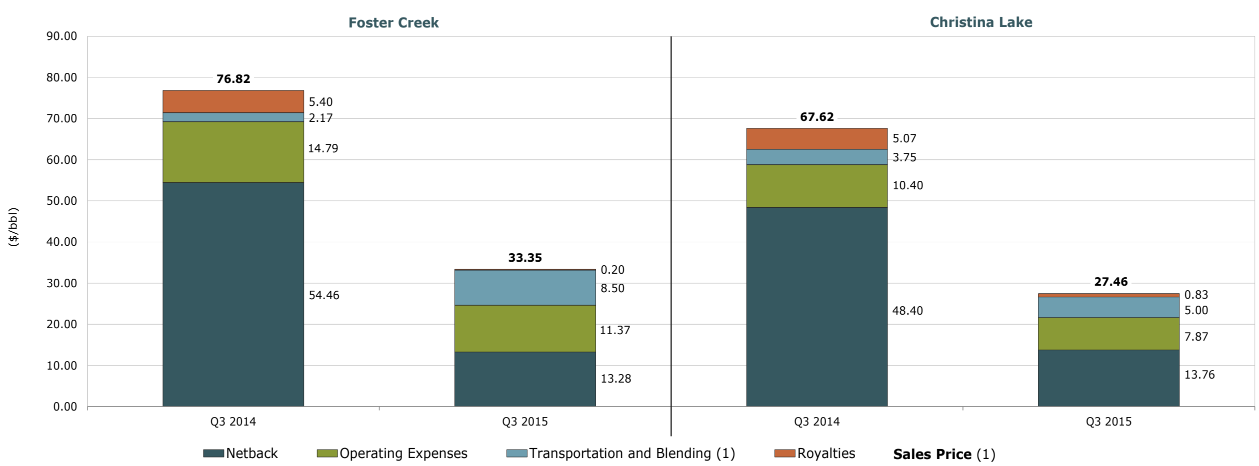
	Three Months Ended September 30,		
($/bbl)	**2015**	**Percent Change**	2014
Foster Creek			
Fuel	**2.65**	**(39)%**	4.31
Non-fuel	**8.72**	**(17)%**	10.48
Total	**11.37**	**(23)%**	14.79
Christina Lake			
Fuel	**2.30**	**(31)%**	3.32
Non-fuel	**5.57**	**(21)%**	7.08
Total	**7.87**	**(24)%**	10.40
Total	**9.55**	**(23)%**	12.41

At Foster Creek, fuel costs decreased $1.66 per barrel primarily due to the decline in natural gas prices and a decrease in fuel consumption on a per-barrel basis.

Non-fuel operating expenses declined $1.76 per barrel primarily due to higher production volumes and lower electricity costs. Workover costs in the third quarter of 2015 included costs savings associated with well servicing and pump changes, but were higher than in 2014. In the third quarter of 2014, after a review of our 2014 re-drilling programs at Foster Creek, certain costs that had previously been recognized as workover costs were capitalized in the third quarter as these activities were beyond normal maintenance and enhanced future production capacity. This reduced third quarter 2014 operating expenses by $1.60 per barrel.

At Christina Lake, fuel costs decreased by $1.02 per barrel primarily due to the decline in natural gas prices. Non-fuel operating expenses decreased $1.51 per barrel, primarily due to lower workover costs related to fewer pump changes, increased production and a decrease in electricity costs.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate in the third quarter was $24.20 per barrel (2014 – $38.50 per barrel) for Foster Creek, and $26.42 per barrel (2014 – $42.57 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

Risk Management

Risk management activities in the third quarter resulted in realized gains of $143 million (2014 – realized losses of $2 million), consistent with our contract prices exceeding average benchmark prices.

Nine Months Ended September 30, 2015 Compared With September 30, 2014

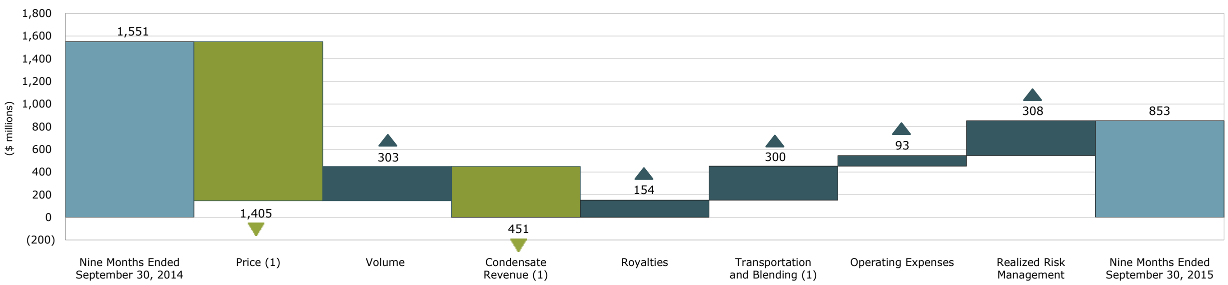
Financial and Per-unit Results

($ millions, unless otherwise noted)	Nine Months Ended September 30, 2015	$ per-unit (1)	Nine Months Ended September 30, 2014	$ per-unit (1)
Gross Sales	**2,356**	63	3,909	117
Less: Royalties	**26**	1	180	5
Revenues	**2,330**	62	3,729	112
Expenses				
Transportation and Blending	**1,336**	36	1,636	48
Operating	**390**	10	483	15
(Gain) Loss on Risk Management	**(249)**	(7)	59	2
Operating Cash Flow	**853**	23	1,551	47
Capital Investment	**945**		1,488	
Operating Cash Flow Net of Related Capital Investment	**(92)**		63	

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

Capital investment in excess of Operating Cash Flow from Oil Sands was funded through Operating Cash Flow generated by our Conventional and Refining and Marketing segments, proceeds from our common share issuance in the first quarter of 2015, and the sale of our royalty interest and mineral fee title lands business in July 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

For the nine months ended September 30, 2015, our average crude oil sales price was $33.56 per barrel, a 53 percent decrease from 2014 as the prices we received continued to be adversely impacted by the worldwide commodity price environment. The decline in our crude oil price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by 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 43 percent to a discount of US$2.51 per barrel (2014 – a discount of US$4.38 per barrel), primarily due to greater access to refineries on the U.S. Gulf Coast that can process a wider variety of heavier crude oils. In the nine months ended September 30, 2015, 86 percent of our Christina Lake production was sold as CDB (2014 – 86 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Nine Months Ended September 30, 2015	Percent Change	2014
Foster Creek	**65,906**	**18%**	56,070
Christina Lake	**74,720**	**11%**	67,400
	140,626	**14%**	123,470

Foster Creek production increased due to production from phase F coming on stream in September 2014, and ramping up as expected, and production from additional wells, partially offset by the impact of the forest fire in the second quarter. The forest fire decreased production by approximately 3,500 barrels per day on a year-to-date basis. Strong initial production has subsided and production rates have returned to levels prior to the forest fire.

Production from Christina Lake increased in the nine months ended September 30, 2015 due to production from additional wells, including wells using our Wedge Well™ technology, phase E reaching nameplate production capacity in the second quarter of 2014, and improved performance of our facilities.

Royalties

Effective Royalty Rates

(percent)	Nine Months Ended September 30, 2015	2014
Foster Creek	**2.1**	8.2
Christina Lake	**3.0**	7.6

Royalties decreased $154 million, primarily related to the decline in crude oil sales prices, partially offset by an increase in sales volumes. At Foster Creek, the royalty calculation was based on gross revenues as compared with a calculation based on net profits for the nine months ended September 30, 2014. In the first quarter of 2015, we received regulatory approval to include certain capital costs incurred in previous years in our royalty calculation and recorded an associated credit, decreasing the overall royalty rate on a year-to-date basis. Excluding the credit, the effective royalty rate for Foster Creek would have been 3.6 percent for the nine months ended September 30, 2015. The Christina Lake royalty rate decreased in 2015 as a result of lower realized sales prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $300 million or 18 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 cost associated with moving the condensate to our oil sands projects.

Transportation costs increased $157 million primarily due to higher pipeline tariffs and additional sales to the U.S. market which attract higher tariffs. To help ensure adequate capacity for our expected future production growth, we have capacity commitments in excess of our current production. Future production growth is expected to reduce our per-barrel transportation costs.

In addition, transportation costs increased as a result of higher volumes moved by rail. In the nine months ended September 30, 2015, we transported an average of 7,889 gross barrels per day of crude oil by rail, consisting of 36 unit train shipments (2014 – 5,285 gross barrels per day, 25 unit train shipments).

Operating

Primary drivers of our operating expenses for the nine months ended September 30, 2015 were workforce, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses decreased $93 million or $4.12 per barrel, primarily as a result of lower natural gas prices that reduced fuel costs, higher production and a decline in workover activities.

Per-unit Operating Expenses

($/bbl)	Nine Months Ended September 30, 2015	Percent Change	2014
Foster Creek			
Fuel	**2.78**	**(42)%**	4.77
Non-fuel	**10.22**	**(21)%**	12.88
Total	**13.00**	**(26)%**	17.65
Christina Lake			
Fuel	**2.22**	**(44)%**	3.98
Non-fuel	**5.91**	**(25)%**	7.89
Total	**8.13**	**(32)%**	11.87
Total	**10.39**	**(28)%**	14.51

At Foster Creek, fuel costs decreased $1.99 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 declined $2.66 per barrel, primarily due to:

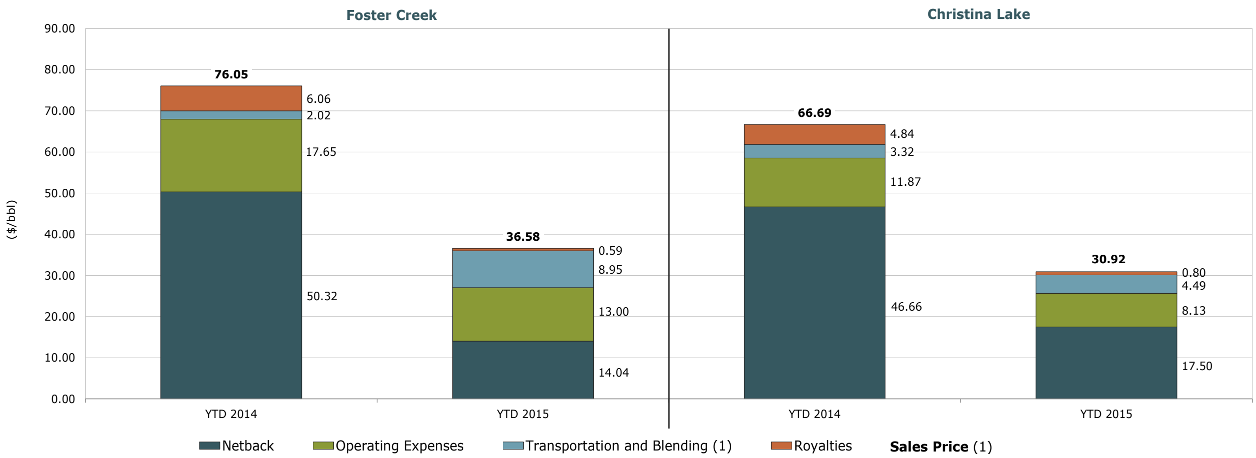
- Higher production volumes;
- A reduction in workover expenses due to lower costs associated with well servicing and pump changes; and
- Lower electricity costs.

Foster Creek non-fuel operating expenses included approximately $2.6 million or $0.15 per barrel of incremental costs associated with the shut-down due to the nearby forest fire that occurred in the second quarter of 2015.

At Christina Lake, fuel costs decreased by $1.76 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 $1.98 per barrel, primarily due to:

- Increased production;
- Lower workover costs related to fewer pump changes; and
- A decrease in repairs and maintenance costs due to a focus on critical operational activities and no turnaround costs in 2015.

Operating Netbacks



(1) The heavy oil price and transportation and blending costs exclude the cost of purchased condensate which is blended with the heavy oil. On a per-barrel of unblended crude oil basis, the cost of condensate for the nine months ended September 30, 2015 was $27.94 per barrel (2014 – $44.49 per barrel) for Foster Creek, and $30.23 per barrel (2014 – $48.02 per barrel) for Christina Lake. Our blending ratios range from approximately 25 percent to 33 percent.

Risk Management

Risk management activities for the nine months ended September 30, 2015 resulted in realized gains of $249 million (2014 – realized losses of $59 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 three and nine months ended September 30, 2015, net of internal usage, was 19 MMcf per day and 20 MMcf per day, respectively (2014 – 23 MMcf per day and 22 MMcf per day, respectively). Operating Cash Flow was $3 million in the third quarter (2014 – $5 million) and $7 million on a year-to-date basis (2014 – $43 million). These decreases were primarily related to the decline in natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Foster Creek	**96**	207	**318**	637
Christina Lake	**147**	198	**515**	563
	243	405	**833**	1,200
Narrows Lake	**12**	38	**41**	130
Telephone Lake	**4**	23	**19**	94
Grand Rapids	**6**	20	**32**	36
Other (1)	**7**	8	**21**	32
Capital Investment (2)	**272**	494	**946**	1,492

(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 current commodity price environment, with a focus on capital discipline 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 expected from an extended period of low commodity prices and market volatility. We plan to focus our 2015 capital investment on base business activities and on our oil sands expansion phases that are expected to generate near-term cash flow.

Existing Projects

Capital investment at Foster Creek in 2015 is 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. In the third quarter, capital investment declined compared with 2014 due to lower spending related to field construction and completion costs associated with the commissioning of phase F in 2014. On a year-to-date basis, capital investment decreased mainly due to lower spending on phase F construction.

In 2015, Christina Lake capital investment is focused on sustaining capital related to existing production, expansion phases F and G, and the optimization project. Capital investment in the third quarter decreased from 2014 primarily due to lower spending on phase F facility detailed engineering and procurement. On a year-to-date basis, capital investment decreased due to lower spending on phase F facilities, partially offset by increased investment in sustaining activities.

Capital investment at Narrows Lake in 2015 is focused on detailed engineering and construction wind-down. Capital investment declined in the third quarter and on a year-to-date basis compared with 2014 due to the suspension of new construction at Narrows Lake until further notice.

Emerging Projects

In 2015, Telephone Lake capital investment has primarily focused on completing front-end engineering work on the central processing facility and preliminary infrastructure development. Capital spending decreased in the third quarter and on a year-to-date basis as we did not drill any stratigraphic test wells in the nine months ended September 30, 2015 (2014 – 45 stratigraphic test wells).

Capital investment at Grand Rapids in 2015 has primarily focused on continued operation of the SAGD pilot project. A third well pair was drilled, completed and commenced steam circulation in the second quarter. Costs incurred with the third SAGD well pair were partially offset by not drilling any stratigraphic test wells in 2015 (2014 – 9 stratigraphic test wells). Capital investment decreased compared with 2014 as all work related to the dismantling and removal of an existing SAGD facility purchased in 2014 has been completed.

Drilling Activity (1)

	Gross Stratigraphic Test Wells (2)		Gross Production Wells (3) (4)	
Nine Months Ended September 30,	**2015**	2014	**2015**	2014
Foster Creek	**122**	147	**21**	61
Christina Lake	**36**	52	**67**	40
	158	199	**88**	101
Narrows Lake	**-**	22	**-**	-
Telephone Lake	**-**	45	**-**	-
Grand Rapids	**-**	9	**1**	-
Other	**-**	21	**-**	-
	158	296	**89**	101

(1) In addition to the drilling activity included within the table, we drilled seven gross service wells in the nine months ended September 30, 2015 (2014 – three gross service wells).

(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 nine months ended September 30, 2015, we drilled seven wells (2014 – 14 wells) 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 low commodity prices will persist for an extended period, we have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging projects only when we believe we will maximize cost savings and capital efficiencies.

Existing Projects

Foster Creek is currently producing from phases A through F. Capital investment for 2015 is forecast to be between $415 million and $435 million. We plan to continue focusing 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 was 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 gross 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 for 2015 is forecast to be between $685 million and $705 million and we plan to continue focusing on sustaining capital related to existing production, expansion phase F and the optimization project. Expansion work on phase F, including cogeneration, is continuing 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 with a ramp-up over a twelve month period. The optimization project began steam injection late in the third quarter of 2015. Spending on phase G engineering and procurement has continued in 2015. Construction work on phase G was deferred earlier this year in response to the low commodity price environment, pushing the expected start-up to beyond 2017. 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 fourth quarter of 2015.

Capital investment at Narrows Lake is forecast to be between $45 million and $50 million in 2015. For the remainder 2015, we plan to continue to focus our capital investment on detailed engineering and procurement. We suspended new construction in response to low commodity prices.

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 $70 million and $80 million in 2015. We plan to continue the pilot project at Grand Rapids and engineering activities at Telephone Lake.

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.

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

($ millions, unless otherwise indicated)	As at December 31, 2014
Upstream Property, Plant and Equipment	**14,644**
Estimated Future Development Capital	**20,084**
Total Estimated Upstream Cost Base	**34,728**
Total Proved Reserves (MMBOE)	**2,393**
Implied Depletion Rate ($/BOE)	**14.51**

While this illustrates the calculation of the implied depletion rate, our depletion rates are slightly higher and result in a total average rate ranging between $15.50 to $16.50 per barrel of oil equivalent. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the three and nine months ended September 30, 2015, Oil Sands DD&A increased $16 million and $49 million, respectively, 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 CO_2 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 while 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.

On July 29, 2015, we completed the sale of our royalty interest and mineral fee title lands business, which included approximately 4.8 million gross acres of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. A royalty on our working interest production from these fee lands and a GORR on production from our Pelican Lake and Weyburn assets were also included in the sale. We received cash proceeds of approximately $3.3 billion and recorded an after-tax gain of approximately $1.9 billion. Associated third party royalty-interest volumes prior to the divestiture were approximately 6,580 barrels of oil equivalent per day.

Additional developments in our Conventional segment in the third quarter of 2015 compared with 2014 include:

- Crude oil production averaging 63,679 barrels per day, decreasing 14 percent, as an increase in production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the sale of our royalty interest and mineral fee title lands business, and the divestiture of a non-core asset in 2014;
- Reduced our crude oil operating costs by $34 million or $2.84 per barrel, compared with 2014;
- Generating Operating Cash Flow net of capital investment of $186 million, a decrease of 34 percent; and
- Resuming drilling activity at our tight oil projects in southeast Alberta and at our CO_2 enhanced oil recovery project at Weyburn.

Conventional – Crude Oil

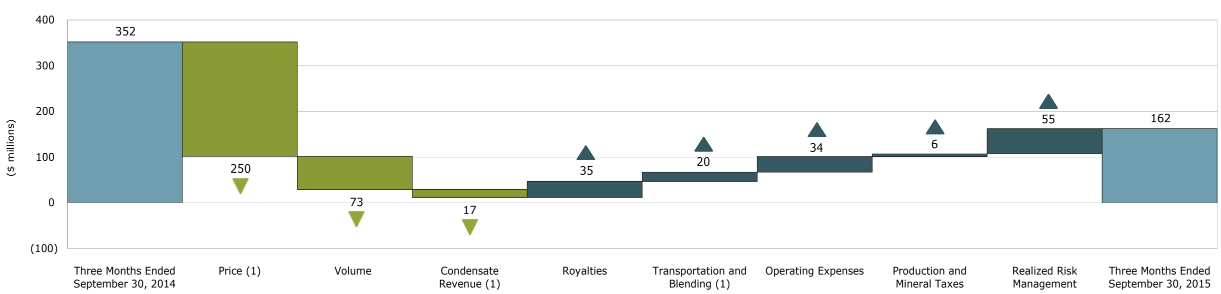
Three Months Ended September 30, 2015 Compared With September 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted)	Three Months Ended September 30, 2015	$ per-unit (1)	Three Months Ended September 30, 2014	$ per-unit (1)
Gross Sales	**279**	48	619	92
Less: Royalties	**23**	4	58	9
Revenues	**256**	44	561	83
Expenses				
Transportation and Blending	**49**	8	69	11
Operating	**90**	16	124	18
Production and Mineral Taxes	**4**	1	10	1
(Gain) Loss on Risk Management	**(49)**	(9)	6	1
Operating Cash Flow	**162**	28	352	52
Capital Investment	**52**		189	
Operating Cash Flow Net of Related Capital Investment	**110**		163	

(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 was $42.43 per barrel in the third quarter, 50 percent lower than in 2014, consistent with the decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**33,997**	**(13)%**	39,096
Light and Medium Oil	**28,491**	**(15)%**	33,548
NGLs	**1,191**	**(12)%**	1,356
	63,679	**(14)%**	74,000

Production declined as higher production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the sale of our royalty interest and mineral fee title lands business, and the divestiture of a non-core asset in 2014. Production from the divested assets was 1,251 barrels per day in the third quarter (2014 – 6,947 barrels per day).

Condensate

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

Royalties

Royalties decreased $35 million primarily due to lower realized sales prices, partially offset by additional royalties at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business. In the third quarter, the effective crude oil royalty rate for our Conventional properties was 10.1 percent (2014 – 10.8 percent).

Crown 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 third quarter of 2015, the Pelican Lake crown royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2014.

Production and mineral taxes decreased, consistent with the decline in crude oil prices and due to the sale of our royalty interest and mineral fee title lands business.

Expenses

Transportation and Blending

Transportation and blending costs decreased $20 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $3 million lower primarily due to a decline in sales volumes and a reduction in volumes moved by rail. In the third quarter of 2015, we did not transport any crude oil by rail (2014 – 1,534 barrels per day).

Operating

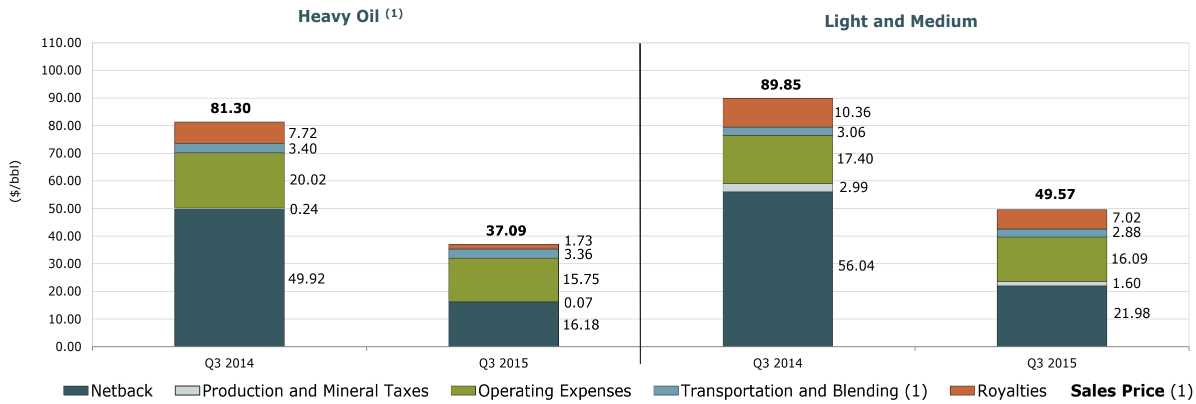
Primary drivers of our operating expenses in the third quarter of 2015 were workforce costs, workover activities, electricity, chemical consumption, and property taxes and lease costs. Operating expenses declined $34 million or $2.84 per barrel.

The per-unit decline was primarily due to:

- A decline in workover costs;
- Lower repairs and maintenance due to a focus on critical operational activities; and
- Lower trucking expenses as we added pipeline infrastructure.

These decreases were partially offset by lower production.

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 $9.56 per barrel in the third quarter (2014 – $13.25 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.

Risk Management

Risk management activities in the third quarter resulted in realized gains of $49 million (2014 – realized losses of $6 million), consistent with our contract prices exceeding average benchmark prices.

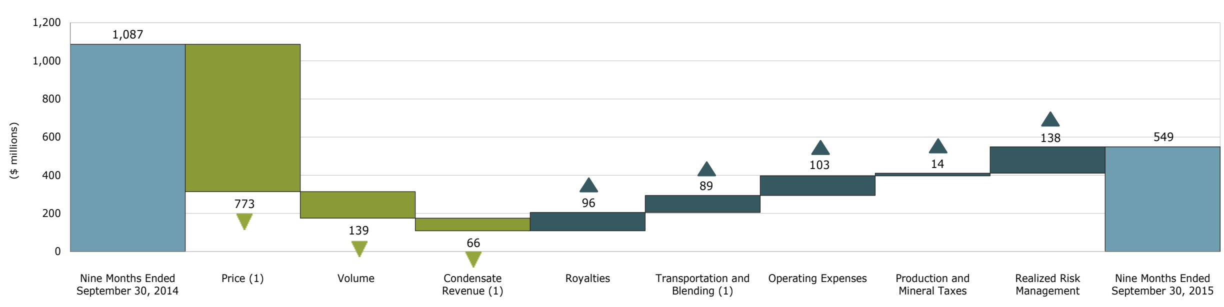
Nine Months Ended September 30, 2015 Compared With September 30, 2014

Financial and Per-unit Results

($ millions, unless otherwise noted)	Nine Months Ended September 30, 2015	$ per-unit (1)	Nine Months Ended September 30, 2014	$ per-unit (1)
Gross Sales	**1,000**	53	1,978	95
Less: Royalties	**78**	4	174	8
Revenues	**922**	49	1,804	87
Expenses				
Transportation and Blending	**160**	8	249	13
Operating	**299**	16	402	19
Production and Mineral Taxes	**14**	1	28	1
(Gain) Loss on Risk Management	**(100)**	(5)	38	2
Operating Cash Flow	**549**	29	1,087	52
Capital Investment	**148**		601	
Operating Cash Flow Net of Related Capital Investment	**401**		486	

(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 47 percent to $46.41 per barrel, consistent with the sustained decline in crude oil benchmark prices.

Production Volumes

(barrels per day)	2015	Percent Change	2014
Heavy Oil	**35,739**	**(11)%**	40,060
Light and Medium Oil	**31,787**	**(8)%**	34,488
NGLs	**1,286**	**7%**	1,200
	68,812	**(9)%**	75,748

Increased production from successful horizontal well performance in southern Alberta was more than offset by expected natural declines, the divestiture of non-core assets in 2014, and the sale of our royalty interest and mineral fee title lands business. Production from the divested assets was 3,417 barrels per day on a year-to-date basis (2014 – 7,293 barrels per day).

Royalties

Royalties decreased $96 million primarily due to lower realized sales prices, partially offset by additional royalties at Pelican Lake, Weyburn and other conventional assets resulting from the sale of our royalty interest and mineral fee title lands business. For the nine months ended September 30, 2015, the effective crude oil royalty rate for our Conventional properties was 9.3 percent (2014 – 10.2 percent). The Pelican Lake royalty calculation was based on net profits in 2015 as compared with a calculation based on gross revenues in 2014.

Production and mineral taxes also decreased, consistent with lower crude oil prices in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $89 million. Blending costs declined primarily due to lower condensate prices. Transportation charges were $23 million lower largely due to a decline in sales volumes and a reduction in volumes moved by rail. In the nine months ended September 30, 2015, we transported an average of 799 barrels per day of crude oil by rail (2014 – 3,099 barrels per day).

Operating

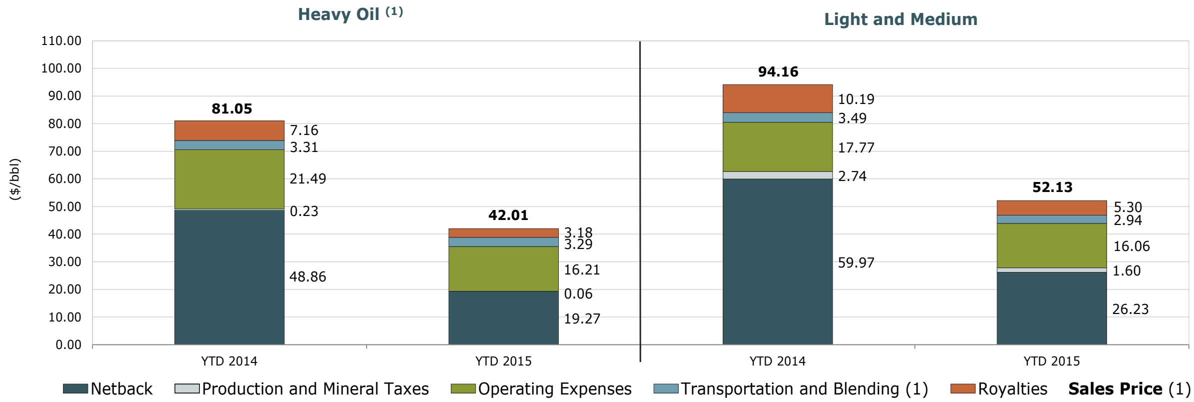
Primary drivers of our operating expenses for the nine months ended September 30, 2015 were workforce costs, workover activities, electricity, chemical consumption, and property taxes and lease costs. Operating expenses declined $103 million or $3.63 per barrel.

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 trucking expenses as we added pipeline infrastructure; and
- Lower electricity costs as a result of a decrease in consumption due in part to the disposition of non-core assets, and a decline in prices.

These decreases were partially offset by lower production.

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 $11.21 per barrel on a year-to-date basis (2014 – $16.23 per barrel). Our blending ratios range from approximately 10 percent to 16 percent.*

Risk Management

Risk management activities for the nine months ended September 30, 2015 resulted in realized gains of $100 million (2014 – realized losses of $38 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Gross Sales	**113**	182	**346**	580
Less: Royalties	**5**	4	**8**	10
Revenues	**108**	178	**338**	570
Expenses				
Transportation and Blending	**3**	5	**12**	14
Operating	**41**	51	**131**	152
Production and Mineral Taxes	**1**	2	**2**	8
(Gain) Loss on Risk Management	**(13)**	(4)	**(38)**	(3)
Operating Cash Flow	**76**	124	**231**	399
Capital Investment	**3**	9	**9**	20
Operating Cash Flow Net of Related Capital Investment	**73**	115	**222**	379

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

Three and Nine Months Ended September 30, 2015 Compared With September 30, 2014

Revenues

Pricing

In the third quarter and on a year-to-date basis, our average natural gas sales price decreased 29 percent to $3.00 per Mcf and 34 percent to $2.97 per Mcf, respectively, consistent with the decline in the AECO benchmark price.

Production

Production decreased 12 percent to 411 MMcf per day in the third quarter (nine percent to 427 MMcf per day on a year-to-date basis) due to expected natural declines and from the sale of our royalty interest and mineral fee title lands business, which produced 6 MMcf per day and 13 MMcf per day in the three and nine months ended September 30, 2015, respectively (2014 – 20 MMcf per day and 20 MMcf per day).

Royalties

Royalties remained consistent compared with the third quarter of 2014 and decreased on a year-to-date basis. Reduced royalties as a result of lower prices and production declines were offset by additional royalties due to the sale of our royalty interest and mineral fee title lands business. The average royalty rate in the third quarter was 4.1 percent (2014 – 2.0 percent) and 2.3 percent (2014 – 1.7 percent) on a year-to-date basis.

Expenses

Transportation

In 2015, transportation costs decreased as a result of lower production volumes, partially offset by higher pipeline tariffs.

Operating

Primary drivers of our operating expenses were property taxes and lease costs, and workforce. In the three and nine months ended September 30, 2015, operating expenses decreased by $10 million and $21 million, respectively, primarily due to lower repairs and maintenance, and workforce, partially offset by lower production volumes.

Risk Management

Risk management activities resulted in realized gains of $13 million in the third quarter and $38 million on a year-to-date basis (2014 – realized gains of $4 million in the third quarter and $3 million on a year-to-date basis), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Heavy Oil	**14**	76	**46**	264
Light and Medium Oil	**38**	113	**102**	337
Natural Gas	**3**	9	**9**	20
Capital Investment [(1)]	**55**	198	**157**	621

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

Capital investment declined in 2015 primarily due to spending reductions on crude oil activities in response to the low commodity price environment. Capital investment in 2015 was primarily related to maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn and drilling activities at our tight oil projects in southeast Alberta.

Conventional Drilling Activity

(net wells, unless otherwise stated)	Nine Months Ended September 30, 2015	2014
Crude Oil	**15**	101
Recompletions	**498**	620
Gross Stratigraphic Test Wells	**-**	18
Other [(1)]	**1**	34

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

Drilling activity declined in 2015, reflecting the decision to suspend the majority of our 2015 drilling program in southern Alberta and Saskatchewan as a result of the low commodity price environment. In the third quarter, some drilling activity resumed at our tight oil projects in southeast Alberta and at our CO_2 enhanced oil recovery project at Weyburn.

Future Capital Investment

Consistent with our expectation that commodity prices will continue to be low for a prolonged period of time, we are planning a more moderate approach to developing our conventional crude oil opportunities. We plan to focus on drilling projects that are considered to be relatively low risk, with short production cycle times and strong expected returns.

Our 2015 crude oil capital investment forecast is between $250 million and $270 million with spending plans mainly focused on maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn and development of our tight oil assets.

DD&A and Exploration Expense

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 decreased $28 million and $34 million for the three and nine months ended September 30, 2015, respectively.

Exploration Expense

Costs incurred after the legal right to explore has been obtained and before technical feasibility and commercial viability have been established are capitalized as E&E assets. If a field, area or project is determined not to be technically feasible and commercially viable or we decide not to continue the exploration activity, the unrecoverable costs are charged to exploration expense.

For the nine months ended September 30, 2015, $21 million (2014 – $nil) of previously capitalized E&E costs related to certain conventional tight oil exploration assets were deemed not to be commercially viable and technically feasible and were recorded as exploration expense.

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 17 percent in the three months ended September 30, 2015, and 13 percent on a year-to-date basis, as compared with 2014, had a positive impact of approximately $36 million and $120 million, respectively, on our refining gross margin.

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

- Closing the purchase of a crude-by-rail terminal for $75 million, plus adjustments, and commencing operations;
- Crude oil runs and refined product output decreasing as a result of unplanned process unit outages at our Borger refinery and the start of a planned turnaround at our Wood River refinery in September 2015; and
- Operating Cash Flow decreasing 57 percent to $29 million primarily due to higher heavy crude oil feedstock costs relative to the WTI benchmark price, higher operating costs and lower refined product output, partially offset by improved margins on the sale of secondary products, an increase in average market crack spreads and weakening of the Canadian dollar relative to the U.S. dollar.

Refinery Operations (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	**2015**	2014
Crude Oil Capacity (2) (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**394**	407	**424**	424
Heavy Crude Oil	**186**	201	**202**	205
Light/Medium	**208**	206	**222**	219
Refined Products (Mbbls/d)	**414**	429	**448**	446
Gasoline	**208**	230	**228**	228
Distillate	**131**	131	**141**	138
Other	**75**	68	**79**	80
Crude Utilization (percent)	**86**	88	**92**	92

(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.

We commenced operations of our crude-by-rail facility at Bruderheim, Alberta, and 12 unit trains, including five unit trains for third parties, were loaded in the first month of operations.

Financial Results

In the third quarter, unplanned process unit outages at our Borger refinery for most of July and the start of a planned turnaround at Wood River reduced crude oil runs and refined product output. The Wood River turnaround is expected to be completed in October. In the third quarter of 2014, we had an unplanned coker outage at Borger that lasted approximately two weeks and a planned turnaround at Wood River.

On a year-to-date basis, crude oil runs and refined product output was consistent with 2014. The unplanned outages at Borger and planned turnarounds at both of our refineries in 2015 had a similar impact on crude oil runs and refined product output as the outage and turnarounds in 2014.

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 volume of heavy crude oil processed in 2015 decreased from 2014 as a result of processing higher volumes of medium crude oils due to more favorable economics.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2015**	2014	**2015**	2014
Revenues	**2,242**	3,144	**6,775**	9,885
Purchased Product	**2,012**	2,918	**5,826**	8,836
Gross Margin	**230**	226	**949**	1,049
Expenses				
Operating	**215**	162	**552**	525
(Gain) Loss on Risk Management	**(14)**	(4)	**(27)**	(9)
Operating Cash Flow	**29**	68	**424**	533
Capital Investment	**67**	42	**159**	111
Operating Cash Flow Net of Related Capital Investment	**(38)**	26	**265**	422

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 third quarter of 2015, the increase in gross margin was primarily due to:

- Improved margins on the sale of our secondary products, such as coke and asphalt, due to lower overall feedstock costs consistent with the decline in WTI;
- Average market crack spreads increased as unplanned refinery outages in the industry caused product inventory drawdowns and slightly improved refined product pricing; and
- Weakening of the Canadian dollar relative to the U.S. dollar.

The increase in gross margin was partially offset by higher heavy crude oil feedstock costs relative to WTI, consistent with the narrowing of the WTI-WCS differential, and lower refined product output.

On a year-to-date basis, the decline 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.

The decrease in gross margin was partially offset by:

- Improved margins on the sale of our secondary products, due to lower overall feedstock costs consistent with the decline in WTI; and
- Weakening of the Canadian dollar relative to the U.S. dollar.

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 third quarter of 2015 and on a year-to-date basis, the cost of our RINs was $27 million and $120 million, respectively (2014 – $29 million and $85 million, respectively). The increase on a year-to-date basis is consistent with the rise in the ethanol RINs benchmark price. This cost remains a minor component of our total refinery feedstock costs.

Operating Expense

Primary drivers of operating expenses in the third quarter of 2015 and on a year-to-date basis were maintenance, labour, utilities and supplies. Operating expenses increased in the three and nine months ended September 30, 2015 compared with 2014 primarily due to weakening of the Canadian dollar relative to the U.S.

dollar, partially offset by a decline in utility costs resulting from lower natural gas prices. In the third quarter, operating expenses were also impacted by higher maintenance costs related to unplanned outages and planned turnaround activities.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Wood River Refinery	**47**	30	**108**	64
Borger Refinery	**19**	12	**49**	47
Marketing	**1**	-	**2**	-
	67	42	**159**	111

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

In 2015, we expect to invest between $220 million and $250 million mainly related to the debottlenecking project at Wood River, in addition to maintenance, reliability and environmental initiatives.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $10 million in the third quarter and $24 million on a year-to-date basis, 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 third quarter, our risk management activities resulted in $127 million of unrealized gains (2014 – $165 million of unrealized gains). On a year-to-date basis, we had $169 million of unrealized losses (2014 – $180 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 September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
General and Administrative	**75**	80	**220**	291
Finance Costs	**122**	105	**359**	337
Interest Income	**(6)**	(4)	**(20)**	(31)
Foreign Exchange (Gain) Loss, Net	**417**	263	**832**	223
Research Costs	**6**	3	**20**	9
(Gain) Loss on Divestiture of Assets	**(2,379)**	(137)	**(2,395)**	(157)
Other (Income) Loss, Net	**(1)**	2	**1**	-
	(1,766)	312	**(983)**	672

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2015 were workforce, office rent and information technology costs. General and administrative expenses decreased by $5 million in the third quarter due to reductions in discretionary spending, offset by higher employee long-term incentive costs. During the third quarter, we incurred severance costs of $3 million related to the previously announced reductions to our workforce. It is expected that additional severance costs of $32 million will be recorded in the fourth quarter.

On a year-to-date basis, general and administrative expenses decreased by $71 million primarily due to lower employee long-term incentive costs driven by the decline in our share price, and lower discretionary spending.

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 increased $17 million in the third quarter ($22 million on a year-to-date basis) compared with 2014 due to higher interest incurred on our U.S. dollar denominated debt due to weakening of the Canadian dollar relative to the U.S. dollar. On a year-to-date basis, the increase was partially offset by lower interest incurred on the Partnership Contribution Payable which was repaid in the first quarter of 2014.

The weighted average interest rate on outstanding debt, excluding the U.S. dollar denominated Partnership Contribution Payable, for the three and nine months ended September 30, 2015 was 5.3 percent (2014 – 5.0 percent).

Foreign Exchange

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Unrealized Foreign Exchange (Gain) Loss	**457**	259	**878**	221
Realized Foreign Exchange (Gain) Loss	**(40)**	4	**(46)**	2
	417	263	**832**	223

The majority of unrealized foreign exchange gains and losses stem from translation of our U.S. dollar denominated debt. The Canadian dollar weakened by seven percent relative to the U.S. dollar from June 30, 2015 to September 30, 2015 resulting in an unrealized loss in the third quarter; the Canadian dollar weakened by 13 percent relative to the U.S. dollar from December 31, 2014 to September 30, 2015 resulting in a year-to-date unrealized loss of $878 million.

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 third quarter of 2015 was $20 million (2014 – $20 million) and $62 million on a year-to-date basis (2014 – $61 million).

Income Tax

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Current Tax				
Canada	**451**	49	**686**	82
United States	**(4)**	(14)	**(10)**	21
Total Current Tax Expense (Recovery)	**447**	35	**676**	103
Deferred Tax Expense (Recovery)	**(228)**	144	**(516)**	396
	219	179	**160**	499

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions)	Nine Months Ended September 30, 2015	2014
Earnings Before Income Tax	**1,419**	1,715
Canadian Statutory Rate	**26.1%**	25.2%
Expected Income Tax	**370**	431
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(15)**	18
Non-Deductible Stock-Based Compensation	**7**	15
Non-Taxable Capital Losses	**113**	33
Unrecognized Capital Losses Arising from Unrealized Foreign Exchange	**113**	33
Adjustments Arising From Prior Year Tax Filings	**(13)**	-
Recognition of Capital Losses	**(149)**	(6)
Recognition of U.S. Tax Basis	**(385)**	-
Change in Statutory Rate	**158**	-
Other	**(39)**	(25)
Total Tax	**160**	499
Effective Tax Rate	**11.3%**	29.1%

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 income 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.

On a year-to-date basis, current tax increased due to the sale of our royalty interest and mineral fee title lands business, and from accelerating the timing of income tax payable as a result of certain corporate restructuring transactions and the decision to maximize availability of future income tax deductions in response to the Alberta corporate income tax rate increasing from 10 percent to 12 percent on July 1, 2015. Of the $447 million of current tax, $391 million is attributed to the sale of the royalty interest and mineral fee title lands business.

In the third quarter of 2015, we recorded a deferred tax recovery of $385 million arising from an adjustment to the tax basis of our refining assets. The increase in tax basis was a result of our partner recognizing a taxable gain on its interest in WRB Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets.

For the nine months ended September 30, 2015, the deferred tax recovery was also due to the reversal of timing differences associated with the recognition of partnership income, unrealized risk management losses and current year operating losses. This was partially offset by a one-time charge of approximately $158 million from the revaluation of the deferred tax liability due to the increase in the Alberta corporate income tax rate.

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.

Our effective tax rate for 2015 differs from the statutory rate due to an increase in tax basis of our U.S. assets, and the recognition of the benefit of capital losses, partially offset by non-deductible foreign exchange losses and a one-time deferred tax expense arising from the Alberta corporate income tax rate increase.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended September 30, 2015	2014	Nine Months Ended September 30, 2015	2014
Net Cash From (Used In)				
Operating Activities	**542**	1,092	**1,152**	2,658
Investing Activities	**2,424**	(463)	**1,357**	(3,552)
Net Cash Provided (Used) Before Financing Activities	**2,966**	629	**2,509**	(894)
Financing Activities	**(134)**	(232)	**1,032**	(457)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(21)**	(1)	**(23)**	55
Increase (Decrease) in Cash and Cash Equivalents	**2,811**	396	**3,518**	(1,296)

	September 30, 2015	December 31, 2014
Cash and Cash Equivalents	**4,401**	883

Operating Activities

Cash from operating activities was $550 million and $1,506 million lower for the three and nine months ended September 30, 2015, respectively, 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 $4,713 million at September 30, 2015 compared with $772 million at December 31, 2014. The increase in working capital was primarily due to the proceeds received from the sale of our royalty interest and mineral fee title lands business in July of 2015 and the common share issuance in the first quarter of 2015.

We anticipate that we will continue to meet our payment obligations as they come due.

Investing Activities

In the third quarter of 2015, cash from investing activities was $2,424 million, a $2,887 million increase from 2014 due to the divestiture of our royalty interest and mineral fee title lands business for proceeds of approximately $2.9 billion, net of current tax, and reduced capital expenditures in response to the low commodity price environment.

On a year-to-date basis, cash from investing activities was $1,357 million, a $4,909 million increase from 2014, primarily due to the divestiture of our royalty interest and mineral fee title lands business. Additionally, we spent

US$1.4 billion to repay the Partnership Contribution Payable in March 2014, which contributed to the overall increase in cash from investing activities from 2014 to 2015.

Financing Activities

Cash used in financing activities decreased $98 million for the three months ended September 30, 2015, primarily due to the 40 percent reduction in our third quarter dividend and a net repayment of short-term borrowings in 2014.

Cash provided by financing activities increased $1,489 million on a year-to-date basis, primarily due to net proceeds from our common share issuance and cash savings from our DRIP, partially offset by a net repayment of short-term borrowings. For the nine months ended September 30, 2015, we had a net repayment of short-term borrowings compared with a net issuance in 2014. We issued 67.5 million common shares at a price of $22.25 per share for net proceeds of $1.4 billion in the first quarter of 2015. We plan to use the net proceeds to partially fund our capital expenditure program for 2015 and for general corporate purposes.

In the third quarter, we paid cash dividends of $0.16 per share or $133 million (2014 – $0.2662 per share or $201 million). On a year-to-date basis, we paid dividends of $0.6924 per share or $578 million of which $396 million was paid in cash with the remainder reinvested in common shares issued from treasury through our DRIP (2014 – $0.7986 per share or $604 million paid in cash). The declaration of dividends is at the sole discretion of the Board and is considered quarterly. While the DRIP continues to be in place, the discount has been discontinued as of July 2015.

Our long-term debt at September 30, 2015 was $6,312 million (December 31, 2014 – $5,458 million) 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 $854 million increase in long-term debt is due to foreign exchange.

As at September 30, 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 September 30, 2015:

($ millions)	Amount	Term
Cash and Cash Equivalents	**4,401**	**Not applicable**
Committed Credit Facility	**1,000**	**November 2017**
Committed Credit Facility	**3,000**	**November 2019**
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

In 2015, Cenovus renegotiated its existing $3.0 billion committed credit facility, extending the maturity date to November 30, 2019. In addition, a new $1.0 billion tranche was established under the same facility, maturing on November 30, 2017. As at September 30, 2015, we had $4.0 billion available 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 September 30, 2015, there was no commercial paper outstanding.

U.S. and Canadian Base Shelf Prospectuses

As at September 30, 2015, no notes were issued under our U.S. or Canadian base shelf prospectuses.

Financial Metrics

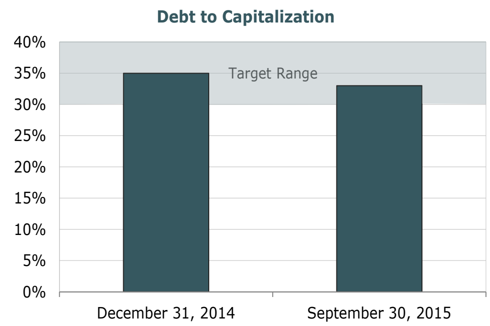
We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. 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.

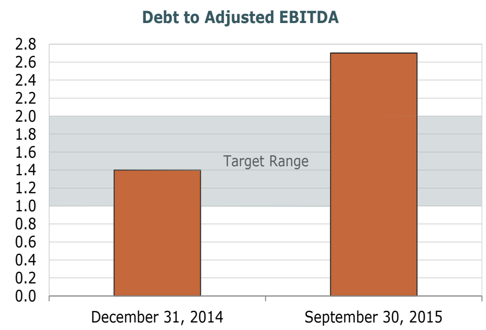
As at	September 30, 2015	December 31, 2014
Debt to Capitalization	**33%**	35%
Net Debt to Capitalization (1) (2)	**13%**	31%
Debt to Adjusted EBITDA (times)	**2.7x**	1.4x
Net Debt to Adjusted EBITDA (times) (1)	**0.8x**	1.2x

(1) Net Debt is defined as Debt net of cash and cash equivalents.
(2) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

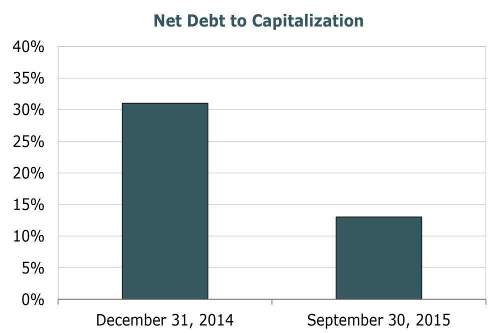
We continue to have long-term targets for a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 times to 2.0 times. At September 30, 2015, our Debt to Capitalization metric was within our target range. Although our Debt to Adjusted EBITDA ratio was above our target of 2.0 times as at September 30, 2015, we believe it will return to within our target range.

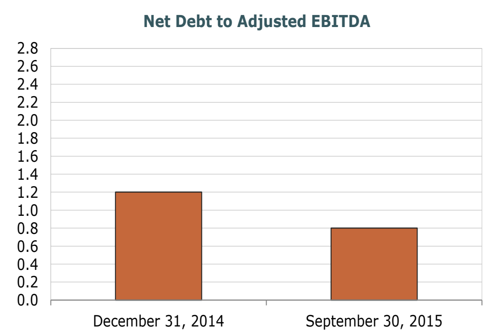
Debt to Capitalization remained consistent as higher debt balances from the weakening of the Canadian dollar relative to the U.S. dollar were offset by the increase in Shareholders' Equity as a result of the common share issuance. The increase in Debt to Adjusted EBITDA was due to higher debt balances 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 September 30, 2015, we held $4.4 billion in cash and cash equivalents. Net Debt to Capitalization and Net Debt to Adjusted EBIDTA were 13 percent and 0.8 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 first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. At September 30, 2015, no preferred shares were outstanding. Cenovus issued 76.2 million common shares during the nine months ended September 30, 2015, including 8.7 million shares issued under the DRIP and 67.5 million shares issued related to the common share issuance in the first quarter of 2015.

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. In the first half of 2015, participants in our DRIP were issued shares from treasury at a three percent discount to the average market price, as defined in the DRIP; this resulted in cash savings of $177 million. For the third quarter dividend, common shares acquired by the DRIP were purchased on the open market. While the DRIP continues to be in place, the discount has been discontinued as of July 2015. Refer to cenovus.com for more details.

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 18 of our interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at September 30, 2015	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	833,290	N/A
Stock Options	46,950	27,462
Other Stock-Based Compensation Plans	11,368	1,459

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. 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.

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. We continue to be exposed to the risks identified in our 2014 annual MD&A in addition to jurisdictional risk.

The following provides an update on our commodity price risk management and jurisdictional risk.

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 20 to the interim Consolidated Financial Statements. The financial impact is summarized below:

Impact of Financial Risk Management Activities

	Three Months Ended September 30,					
	2015			2014		
($ millions)	Realized	Unrealized	Total	Realized	Unrealized	Total
Crude Oil	(195)	(141)	(336)	9	(159)	(150)
Natural Gas	(15)	15	-	(5)	-	(5)
Refining	(14)	(7)	(21)	(4)	(7)	(11)
Power	4	6	10	-	1	1
(Gain) Loss on Risk Management	(220)	(127)	(347)	-	(165)	(165)
Income Tax Expense (Recovery)	59	34	93	-	43	43
(Gain) Loss on Risk Management, After Tax	(161)	(93)	(254)	-	(122)	(122)

($ millions)	Nine Months Ended September 30, 2015 Realized	Unrealized	Total	2014 Realized	Unrealized	Total
Crude Oil	**(355)**	**120**	**(235)**	95	(173)	(78)
Natural Gas	**(43)**	**41**	**(2)**	(4)	(2)	(6)
Refining	**(26)**	**5**	**(21)**	(8)	(5)	(13)
Power	**7**	**3**	**10**	2	-	2
(Gain) Loss on Risk Management	**(417)**	**169**	**(248)**	85	(180)	(95)
Income Tax Expense (Recovery)	**112**	**(48)**	**64**	(21)	47	26
(Gain) Loss on Risk Management, After Tax	**(305)**	**121**	**(184)**	64	(133)	(69)

In the three and nine months ended September 30, 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. In the third quarter, we recorded unrealized gains on our crude oil financial instruments as a result of changes in market prices. On a year-to-date basis, we recorded unrealized losses on our crude oil and natural gas financial instruments primarily due to the realization of settled positions partially offset by changes in market prices.

Jurisdictional Risk

The Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans. We are cautiously awaiting the results of the planned royalty review before finalizing plans to begin reinvesting capital in previously deferred oil sands expansion projects.

The newly elected Federal Liberal government may implement new environmental legislation and regulatory oversight, which may have a significant impact on the oil and gas industry. Potential pipeline opposition may result in wider differentials between Canadian heavy blends and North American benchmarks.

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 during the nine months ended September 30, 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 during the nine months ended September 30, 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 nine months ended September 30, 2015.

Future Accounting Pronouncements

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing International Accounting Standard 11, "*Construction Contracts*", International Accounting Standard 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

On September 11, 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. Early adoption is still permitted. The standard may be applied retrospectively or using a modified retrospective approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements.

Additional Standards

A description of additional standards and interpretations that will be adopted 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 September 30, 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 CR reporting activities are guided by this policy and 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 September 2015, our CR practices were recognized internationally with the inclusion of Cenovus to the Dow Jones Sustainability World Index for the fourth consecutive year. We were also named to the Dow Jones Sustainability North America Index for the sixth consecutive year.

In June 2015, Cenovus was named one of the Top 50 Socially Responsible Corporations in Canada by Maclean's magazine and Sustainalytics for the fourth year in a row and for the fifth consecutive year by Corporate Knights magazine as one of the 2015 Best 50 Corporate Citizens in Canada. We were also included in the Euronext Vigeo World 120 Index for the second year. This index recognizes the top 120 companies globally for their high degree of control of corporate responsibility risk and contributions to sustainable development.

In February 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 is also part of the FTSE4Good Index series and the MSCI Global Sustainability Index series. These internationally recognized benchmarks are designed to measure the performance of companies demonstrating strong environmental, social and governance practices.

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

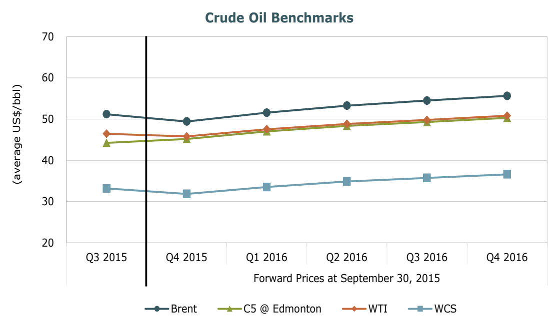
OUTLOOK

We expect the remainder of 2015 to continue to be a challenging time for our industry. We anticipate prices will remain low in the fourth quarter of 2015 and into 2016. 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. We continue to pursue our long-term strategy at a pace we believe is in line with the current commodity price environment.

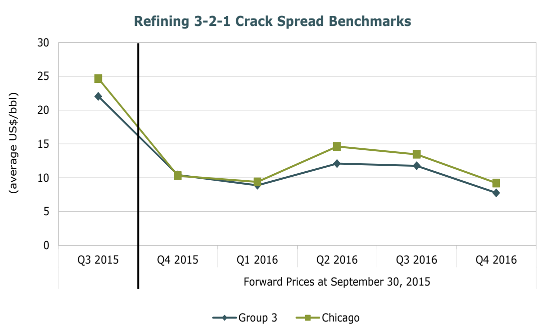
The following outlook commentary is focused on the next fifteen months.

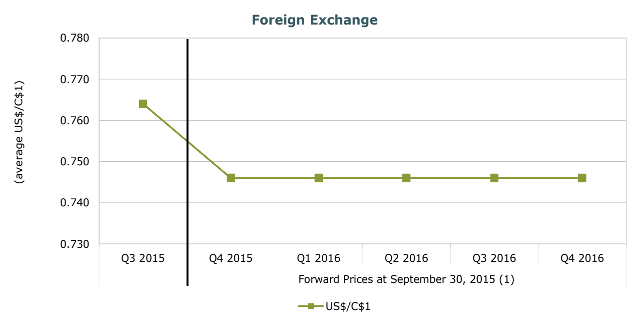
Commodity Prices Underlying our Financial Results

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 supply response to the current price environment and the pace of growth of the global economy. Overall, we expect crude oil price volatility in the fourth quarter of 2015 and a modest price improvement in 2016. Slower global supply growth, combined with annual increases in demand growth, should support prices for the next fifteen months, constrained by the need to draw down surplus crude oil inventories and anticipated re-entry of Iranian crude oil into markets. We continue to anticipate slower supply growth from North American producers as a result of the significant reductions in capital spending. The low crude oil price environment also serves to help boost global economic momentum. We believe there is a risk that OPEC will attempt to gain market share by increasing rig counts or increasing OPEC production, which will depress crude oil prices, and that economic uncertainty in China may slow emerging market demand;
- We expect the Brent-WTI differential to remain near current levels primarily because of high international crude oil storage levels and slowing U.S. supply growth. Overall, the differential will likely be set by transportation costs. The Brent-WTI differential is expected to remain volatile due to mismatches in demand, global imports and refinery turnarounds; and
- We also expect that the WTI-WCS differential will widen from currently narrow levels due to expected Canadian supply growth and declining U.S. light tight oil supply. However, substantially wider differentials are unlikely due to excess rail capacity and further expansions on existing pipeline systems.





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

Refining crack spreads in 2016, as forecasted at September 30, 2015, are expected to strengthen around the second quarter when refineries conduct their seasonal turnaround activities.

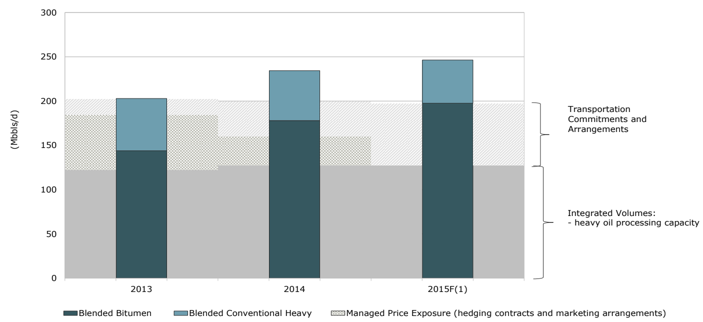
Natural gas production is anticipated to increase in the fourth quarter of 2015 as coal-to-gas substitution in the power sector is expected to continue to be the swing demand to balance the market. As a result, natural gas prices are expected to remain weak for the remainder of 2015 and through the first half of 2016.

The average foreign exchange forward price expected over the next fifteen months is US$0.746/C$. Canadian federal election results, commodity prices and the timing of a U.S. interest rate increase are expected to influence future foreign exchange fluctuations. We expect that the Canadian dollar, compared with the U.S. dollar, will remain relatively weak in the near term due to Canadian political and economic uncertainty, and then gradually strengthen as 2016 progresses and commodity prices improve. Overall, a weak Canadian dollar should have a positive impact on our revenues and Operating Cash Flow.

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

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 in the remainder of 2015 and into 2016. Together, our share issuance in the first quarter of 2015 and the sale of our royalty interest and mineral fee title lands business in July 2015 raised cash proceeds of approximately $4.7 billion. These transactions strengthen our balance sheet and provide us with greater financial resilience during these uncertain times to consider investing in opportunities that we believe have strong future returns.

With an additional $2.9 billion of cash on hand after the divestiture of our royalty interest and mineral fee title lands business, we have started to reinvest capital into expansion projects that were previously deferred to 2016.

Our capital planning process remains flexible. We have adopted a more moderate and staged approach to future oil sands expansions. We will consider expanding existing projects and developing emerging opportunities only when we believe we will maximize cost savings and capital efficiencies to generate the greatest potential return for shareholders. We will continue to assess our spending plans on a regular basis while closely monitoring crude oil prices in the fourth quarter of 2015 and into 2016.

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 functional business model. In the nine months ended September 30, 2015, we captured significant savings from capital, operating and general and administrative cost reductions. As a result, we anticipate savings of approximately $400 million for the full year. As previously announced, in light of sustained low commodity price environment and our plan to moderate our pace of growth, we made substantial reductions to our workforce in 2015.

Enable Market Access

We continue to focus on near- and mid-term strategies to broaden market access for our crude oil production, as illustrated by our purchase of a crude-by-rail terminal and securing a license to export crude oil from the U.S. Gulf Coast. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving 10 percent 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

The Alberta NDP provincial government is proceeding with plans to study, and potentially modify, Alberta's royalty structure and increase carbon levies. A change in the Alberta provincial royalty structure could have a significant impact on Cenovus's future financial results, cost of capital and capital investment plans.

The newly elected Federal Liberal government may implement new environmental legislation and regulatory oversight, which may have a significant impact on the oil and gas industry. Potential pipeline opposition may result in wider differentials between Canadian heavy blends and North American benchmarks.

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

ADVISORY

Oil and Gas Information

The estimates of reserves and resources data and related information were prepared effective December 31, 2014 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. Estimates are presented using McDaniel & Associates Consultants Ltd. January 1, 2015 price forecast. For additional information about our reserves, resources and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2014.

Barrels of Oil Equivalent - Natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

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", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes, including statements about our strategy and related milestones and schedules, projected future value, projections for 2015 and future years, forecast operating and financial results, targets for our Debt to Capitalization and Debt to EBITDA ratios, 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, expected future transportation capacity, 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 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 819 million. It assumes: Brent of US$54.75/bbl, WTI of US$49.70/bbl; WCS of US$36.30/bbl; NYMEX of US$2.75/MMBtu; AECO of $2.65/GJ; Chicago 3-2-1 crack spread of US$18.10/bbl; and an exchange rate of $0.78 US$/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; risks inherent in operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of debt to adjusted EBITDA and net debt to adjusted EBITDA as well as debt to capitalization and net 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 December 31, 2014, 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
BOE/d	barrel of oil equivalent per day
MBOE	thousand barrel of oil equivalent
MMBOE	million barrel of oil equivalent
TM	Trademark of Cenovus Energy Inc.