MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED SEPTEMBER 30, 2016

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 26, 2016, should be read in conjunction with our September 30, 2016 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2015 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2015 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of October 26, 2016, 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 shares listed on the Toronto and New York stock exchanges. On September 30, 2016, we had a market capitalization of approximately $16 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and 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, 2016 was approximately 201,300 barrels per day and our average natural gas production was 399 MMcf per day. Our refineries processed an average of 452,000 gross barrels per day of crude oil feedstock into an average of 479,000 gross barrels per day of refined products.

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, 2016		
	Ownership Interest (percent)	**Net Production Volumes** (bbls/d)	**Gross Production Volumes** (bbls/d)
Existing Projects			
Foster Creek	**50**	**66,435**	**132,870**
Christina Lake	**50**	**78,321**	**156,642**
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 of northeastern Alberta, respectively.

	Nine Months Ended September 30, 2016	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Cash Flow	**542**	**4**
Capital Investment	**472**	**4**
Operating Cash Flow Net of Related Capital Investment	**70**	**-**

Conventional

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

	Nine Months Ended September 30, 2016	
($ millions)	**Crude Oil (1)**	**Natural Gas**
Operating Cash Flow	**302**	**87**
Capital Investment	**108**	**6**
Operating Cash Flow Net of Related Capital Investment	**194**	**81**

(1) Includes NGLs.

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

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with and operated by Phillips 66, an unrelated U.S. public company. The gross crude oil capacity at the Wood River and Borger refineries is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. 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 light/heavy crude oil price 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, 2016
Operating Cash Flow	238
Capital Investment	156
Operating Cash Flow Net of Related Capital Investment	**82**

QUARTERLY HIGHLIGHTS

Crude oil prices remained relatively flat in the third quarter compared with the second quarter of 2016 with the West Texas Intermediate ("WTI") benchmark price averaging US$44.94 per barrel. Our average crude oil sales price was $34.64 per barrel in the quarter, a slight increase from $33.87 per barrel in the second quarter and more than double first quarter prices.

Our crude oil netback, before realized risk management activities, was $17.17 per barrel, a 12 percent increase from the third quarter of 2015. Year to date, our netback was $10.32 per barrel, which remains significantly lower than in 2015. We continue to focus on maintaining our financial resilience and safe and reliable operations. Our ongoing efforts to reduce costs have helped our balance sheet remain strong, with approximately $3.9 billion of cash on hand at September 30, 2016.

In the third quarter, we:

- Decreased our total crude oil operating costs by 14 percent or $1.54 per barrel, compared with 2015;
- Achieved Cash Flow of $422 million, a decrease of five percent from the third quarter of 2015 primarily due to lower realized gains on risk management activities;
- Incurred Operating Losses of $236 million or $9.28 per BOE sold compared with Operating Losses of $28 million or $1.08 per BOE sold in the third quarter of 2015;
- Added incremental crude oil production volumes from Foster Creek phase G and began steam generation at Christina Lake phase F. These phases, which include cogeneration at Christina Lake phase F, are expected to add 80,000 gross barrels per day of production capacity;
- Increased crude utilization as a result of strong performance at both refineries. In addition, the debottlenecking project at Wood River was successfully completed and is expected to increase our heavy crude oil processing capability by 18,000 gross barrels per day; and
- Recorded asset impairments of $292 million due to a decline in long-term forward commodity prices.

OPERATING RESULTS

Total crude oil production decreased slightly in the three and nine months ended September 30, 2016, as higher production from our Oil Sands segment was offset by lower production from our Conventional properties.

Crude Oil Production Volumes

	Three Months Ended September 30,			Nine Months Ended September 30,		
(barrels per day)	**2016**	**Percent Change**	2015	**2016**	**Percent Change**	2015
Oil Sands						
Foster Creek	**73,798**	**3%**	71,414	**66,435**	**1%**	65,906
Christina Lake	**79,793**	**6%**	75,329	**78,321**	**5%**	74,720
	153,591	**5%**	146,743	**144,756**	**3%**	140,626
Conventional						
Heavy Oil	**28,096**	**(17)%**	33,997	**29,276**	**(18)%**	35,739
Light and Medium Oil	**25,311**	**(11)%**	28,491	**26,200**	**(18)%**	31,787
NGLs [(1)]	**1,074**	**(10)%**	1,191	**1,027**	**(20)%**	1,286
	54,481	**(14)%**	63,679	**56,503**	**(18)%**	68,812
Total Crude Oil Production	**208,072**	**(1)%**	210,422	**201,259**	**(4)%**	209,438

(1) *NGLs include condensate volumes.*

In the third quarter and on a year-to-date basis, production rose at Foster Creek primarily due to incremental production volumes from the phase G facility and additional wells being brought online. Ramp-up of phase G is on track and is expected to take 18 months. In the nine months ended September 30, 2015, production was decreased by approximately 3,500 barrels per day due to a nearby forest fire which resulted in the temporary shutdown of operations in the second quarter.

Production from Christina Lake increased in the three and nine months ended September 30, 2016 due to additional wells being brought online, incremental production from the optimization project completed in 2015 and reliable performance of our facilities.

Our Conventional crude oil production decreased in the third quarter and on a year-to-date basis due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in July 2015. Divested assets contributed an average of 1,250 barrels per day and 3,415 barrels per day, respectively, in the three and nine months ended September 30, 2015.

Natural Gas Production Volumes

	Three Months Ended September 30,		Nine Months Ended September 30,	
(MMcf per day)	**2016**	2015	**2016**	2015
Conventional	**374**	411	**382**	427
Oil Sands	**18**	19	**17**	20
	392	430	**399**	447

In the third quarter and on a year-to-date basis, our natural gas production decreased nine percent and 11 percent, respectively. Production was lower primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015.

Operating Netbacks

	Three Months Ended September 30, Crude Oil (1) ($/bbl)		Three Months Ended September 30, Natural Gas ($/Mcf)		Nine Months Ended September 30, Crude Oil (1) ($/bbl)		Nine Months Ended September 30, Natural Gas ($/Mcf)	
	2016	2015	**2016**	2015	**2016**	2015	**2016**	2015
Price (2)	**34.64**	34.03	**2.49**	3.00	**28.25**	37.90	**2.11**	2.96
Royalties	**1.84**	1.60	**0.10**	0.11	**1.57**	1.85	**0.08**	0.06
Transportation and Blending (2)	**5.71**	5.61	**0.10**	0.10	**6.02**	5.39	**0.11**	0.11
Operating Expenses (3)	**9.74**	11.28	**1.05**	1.16	**10.19**	12.15	**1.11**	1.19
Production and Mineral Taxes	**0.18**	0.23	**0.01**	0.01	**0.15**	0.25	**-**	0.01
Netback Excluding Realized Risk Management	**17.17**	15.31	**1.23**	1.62	**10.32**	18.26	**0.81**	1.59
Realized Risk Management Gain (Loss)	**2.14**	10.07	**-**	0.37	**4.06**	6.25	**-**	0.35
Netback Including Realized Risk Management	**19.31**	25.38	**1.23**	1.99	**14.38**	24.51	**0.81**	1.94

(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 $18.46 per barrel for the third quarter (2015 – $19.18 per barrel) and $19.40 per barrel for the nine months ended September 30, 2016 (2015 – $21.32 per barrel).*
(3) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Our average crude oil netback, excluding realized risk management gains and losses, increased 12 percent in the three months ended September 30, 2016 compared with 2015. The increase was primarily due to lower operating expenses and higher average sales prices, partially offset by higher royalties. Royalties increased primarily due to additional royalty burdens resulting from the sale of our royalty interest and mineral fee title lands business in 2015. Our average sales price increased primarily due to the decline in the cost of condensate used for blending in the third quarter of 2016 compared with 2015. As the cost of condensate decreases relative to the price of blended crude oil, our bitumen and heavy oil sales price increases. Refer to the Reportable Segments section for more details.

On a year-to-date basis, our average crude oil netback, excluding realized risk management gains and losses, declined 43 percent compared with 2015. The decline was primarily due to lower average sales prices and lower royalties, partially offset by a decline in operating expenses. The decrease in price is consistent with the decline in benchmark prices and a widening of the WTI-Western Canadian Select ("WCS") differential, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar, a decline in the cost of condensate used in blending and increased sales into the U.S. market, which generally secures a higher sales price. Our year-to-date netbacks were strongly impacted by crude oil sales prices in the first quarter which were approximately 50 percent lower than our crude oil sales prices in the second and third quarters.

In the third quarter, the value of the Canadian dollar relative to the U.S. dollar was consistent with the value in 2015. The weakening of the Canadian dollar relative to the U.S. dollar on a year-to-date basis, compared with 2015, had a positive impact on our crude oil price of approximately $1.32 per barrel.

In 2016, 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

In the third quarter, crude utilization increased due to consistent performance at both the Wood River and Borger refineries. In September, there was unplanned maintenance at the Borger refinery. As a result, a portion of the maintenance originally scheduled for October was started in the third quarter. In the third quarter of 2015, crude utilization was reduced by unplanned process unit outages at the Borger refinery for most of July and the start of a planned turnaround at the Wood River refinery.

On a year-to-date basis, crude utilization increased. Strong performance at both refineries was slightly offset by planned and unplanned maintenance at both refineries in the first quarter of 2016 and unplanned maintenance at the Borger refinery in September. In 2015, we experienced unplanned outages at the Borger refinery and planned turnarounds at both refineries.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2016	**Percent Change**	2015	**2016**	**Percent Change**	2015
Crude Oil Runs [1] (Mbbls/d)	**463**	**18%**	394	**452**	**7%**	424
Heavy Crude Oil [1]	**241**	**30%**	186	**237**	**17%**	202
Refined Product [1] (Mbbls/d)	**494**	**19%**	414	**479**	**7%**	448
Crude Utilization [1] (percent)	**101**	**15%**	86	**98**	**6%**	92

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

Further information on the changes in our production volumes, items included in our operating netbacks and refining results 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.

Crude Oil Benchmarks

Average crude oil benchmark prices in the third quarter were relatively consistent with the second quarter of 2016 and six percent lower than in the third quarter of 2015. Crude oil prices continued to be volatile, driven by stronger production from Saudi Arabia and Iran in combination with higher seasonal demand and lower gasoline prices for consumers. Additional volatility was introduced in late September when the Organization of Petroleum Exporting Countries ("OPEC") announced a plan to limit its crude oil production.

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 of 2016 and on a year-to-date basis compared with 2015 as a result of lifting the U.S. export ban and a decrease in U.S. domestic light oil supply. The Brent-WTI differential continues to be primarily driven by transportation costs.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. Despite the decline in WTI, the average WTI-WCS differential was wider in the third quarter of 2016 and on a year-to-date basis compared with 2015. The differential widened as additional U.S. imports of medium crude competed for refining capacity and heavy oil prices were pressured by an oversupply of heavy oil products, such as fuel oil and bunker fuel.

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. Since the supply of condensate in Alberta does not meet demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost attributed to transporting the condensate to Edmonton.

Average condensate prices were stronger relative to WTI in the third quarter of 2016 and on a year-to-date basis as declining U.S. light oil production reduced condensate supply from the U.S. Gulf Coast while higher heavy oil production in Alberta increased demand.

Selected Benchmark Prices and Exchange Rates [1]

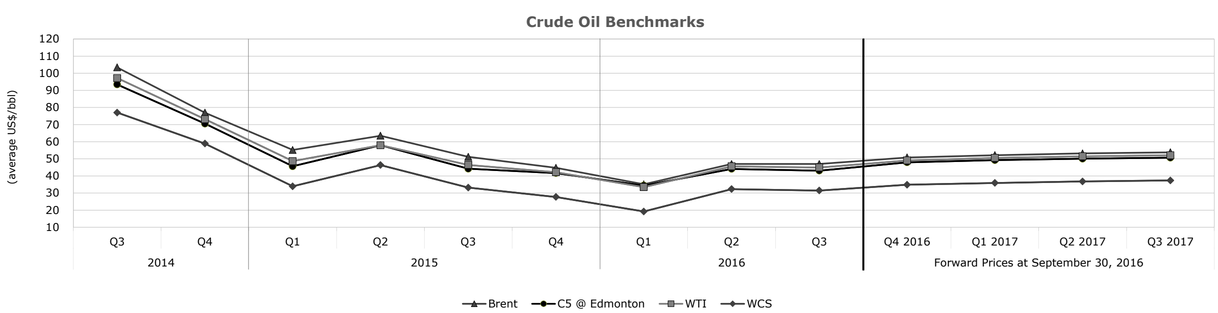
	Nine Months Ended September 30, 2016	Percent Change	2015	Q3 2016	Q2 2016	Q3 2015
Crude Oil Prices (US$/bbl)						
Brent						
Average	**43.01**	**(24)%**	56.61	**46.98**	46.97	51.17
End of Period	**49.06**	**1%**	48.37	**49.06**	49.68	48.37
WTI						
Average	**41.33**	**(19)%**	51.00	**44.94**	45.59	46.43
End of Period	**48.24**	**7%**	45.09	**48.24**	48.33	45.09
Average Differential Brent-WTI	**1.68**	**(70)%**	5.61	**2.04**	1.38	4.74
WCS [2]						
Average	**27.65**	**(27)%**	37.80	**31.44**	32.29	33.16
End of Period	**34.97**	**11%**	31.62	**34.97**	35.79	31.62
Average Differential WTI-WCS	**13.68**	**4%**	13.20	**13.50**	13.30	13.27
Condensate (C5 @ Edmonton) [3]						
Average	**40.51**	**(18)%**	49.25	**43.07**	44.07	44.21
Average Differential WTI-Condensate (Premium)/Discount	**0.82**	**(53)%**	1.75	**1.87**	1.52	2.22
Average Differential WCS-Condensate (Premium)/Discount	**(12.86)**	**12%**	(11.45)	**(11.63)**	(11.78)	(11.05)
Average Refined Product Prices (US$/bbl)						
Chicago Regular Unleaded Gasoline ("RUL")	**55.17**	**(23)%**	71.82	**59.27**	64.25	73.05
Chicago Ultra-low Sulphur Diesel ("ULSD")	**54.60**	**(23)%**	71.09	**59.86**	59.40	67.02
Refining Margin: Average 3-2-1 Crack Spreads (US$/bbl)						
Chicago	**13.77**	**(33)%**	20.66	**14.58**	17.15	24.67
Group 3	**12.71**	**(35)%**	19.61	**14.56**	13.03	22.03
Average Natural Gas Prices						
AECO (C$/Mcf)	**1.85**	**(34)%**	2.81	**2.20**	1.25	2.80
NYMEX (US$/Mcf)	**2.29**	**(18)%**	2.80	**2.81**	1.95	2.77
Basis Differential NYMEX-AECO (US$/Mcf)	**0.89**	**59%**	0.56	**1.13**	0.99	0.61
Foreign Exchange Rates (US$ per C$1)						
Average	**0.757**	**(5)%**	0.794	**0.766**	0.776	0.764

(1) *These benchmark prices do not reflect our sales prices. For our average 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 of 2016 was $41.04 per barrel (2015 – $43.40 per barrel) and for the nine months ended September 30, 2016 was $36.53 per barrel (2015 – $47.61 per barrel).*

(3) *The average Canadian dollar condensate benchmark price for the third quarter of 2016 was $56.23 per barrel (2015 – $57.87 per barrel) and for the nine months ended September 30, 2016 was $53.51 per barrel (2015 – $62.03 per barrel).*

Crude Oil Benchmarks

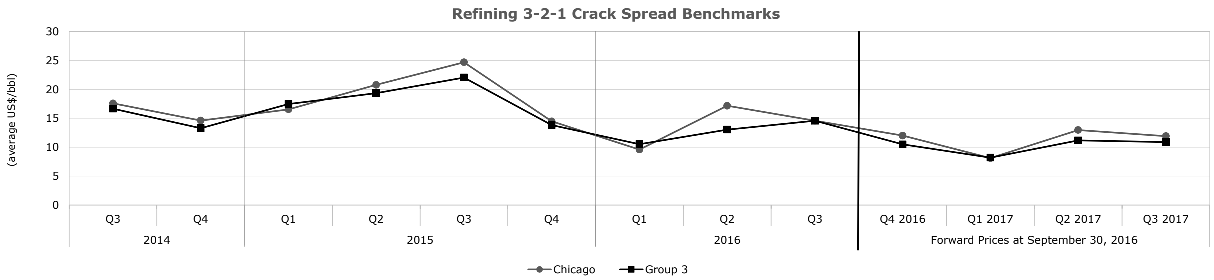


Refining Benchmarks

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 Chicago and Group 3 crack spreads decreased in the three and nine months ended September 30, 2016 compared with 2015 due to higher global refined product inventory and strengthening of the WTI benchmark price compared with Brent, as evidenced by narrowing of the Brent-WTI differential.

Our realized crack spreads are affected by many other factors such as the variety of feedstock crude oil, 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 2016 and on a year-to-date basis compared with 2015 primarily due to high inventory levels in North America given a warmer than normal 2015/2016 winter and the resiliency of North American supply.

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 chose 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, compared with 2015, the Canadian dollar relative to the U.S. dollar was largely unchanged. On a year-to-date basis, the Canadian dollar weakened relative to the U.S. dollar due to lower commodity prices and the expectation of higher U.S. interest rates. The weakening of the Canadian dollar for the nine months ended September 30, 2016 compared with 2015, had a positive impact of approximately $397 million on our revenues. As at September 30, 2016, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2015, which resulted in $343 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt for the nine months ended September 30, 2016.

FINANCIAL RESULTS

Selected Consolidated Financial Results

While crude oil prices in the third quarter improved from the first half of 2016, they were lower than in 2015 and had a significant impact on our year-to-date financial results. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	Nine Months Ended September 30,		**2016**			2015				2014	
	2016	2015	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenues	**8,492**	10,140	**3,240**	3,007	2,245	2,924	3,273	3,726	3,141	4,238	4,970
Operating Cash Flow (1) (2)	**1,172**	2,082	**487**	541	144	357	602	932	548	537	1,156
Cash Flow (1)	**888**	1,416	**422**	440	26	275	444	477	495	401	985
Operating Earnings (Loss) (1)	**(698)**	35	**(236)**	(39)	(423)	(438)	(28)	151	(88)	(590)	372
Per Share – Diluted	**(0.84)**	0.04	**(0.28)**	(0.05)	(0.51)	(0.53)	(0.03)	0.18	(0.11)	(0.78)	0.49
Net Earnings (Loss)	**(636)**	1,259	**(251)**	(267)	(118)	(641)	1,801	126	(668)	(472)	354
Per Share – Basic and Diluted	**(0.76)**	1.55	**(0.30)**	(0.32)	(0.14)	(0.77)	2.16	0.15	(0.86)	(0.62)	0.47
Capital Investment (3)	**767**	1,286	**208**	236	323	428	400	357	529	786	750
Dividends											
Cash Dividends	**124**	396	**41**	42	41	132	133	125	138	201	201
In Shares from Treasury	**-**	182	**-**	-	-	-	-	98	84	-	-
Per Share	**0.15**	0.6924	**0.05**	0.05	0.05	0.16	0.16	0.2662	0.2662	0.2662	0.2662

(1) *Non-GAAP measure defined in this MD&A.*
(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*
(3) *Includes expenditures on Property, Plant and Equipment ("PP&E") and Exploration and Evaluation ("E&E") assets.*

Revenues

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2015	**3,273**	**10,140**
Increase (Decrease) due to:		
Oil Sands	**40**	**(388)**
Conventional	**(73)**	**(462)**
Refining and Marketing	**3**	**(813)**
Corporate and Eliminations	**(3)**	**15**
Revenues for the Periods Ended September 30, 2016	**3,240**	**8,492**

Combined Oil Sands and Conventional revenues declined three percent in the third quarter, compared with 2015, primarily due to lower natural gas sales prices and volumes, partially offset by an increase in crude oil sales prices. On a year-to-date basis, combined Oil Sands and Conventional revenues decreased 23 percent primarily due to lower crude oil and natural gas sales prices and a decline in sales volumes, partially offset by the weakening of the Canadian dollar relative to the U.S. dollar. The sale of our royalty interest and mineral fee title lands business in 2015 also reduced revenues.

Revenues from our Refining and Marketing segment in the third quarter of 2016 remained relatively flat as lower refined product pricing, consistent with lower Chicago RUL and Chicago ULSD benchmark prices, was offset by higher refined product output. On a year-to-date basis, refining revenues declined 12 percent due to lower refined product pricing, partially offset by higher refined product output and the weakening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party sales undertaken by the marketing group increased from 2015 due to higher purchased crude oil and natural gas volumes, partially offset by lower natural gas sales prices. Crude oil sales prices increased in the third quarter compared with 2015 and declined on a year-to-date basis.

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.

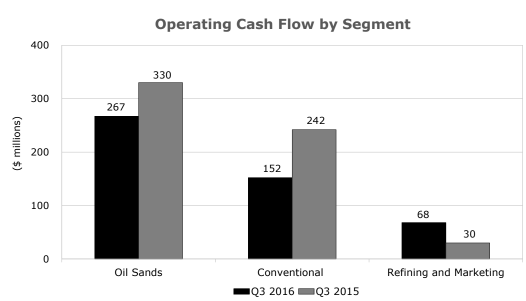
Operating Cash Flow

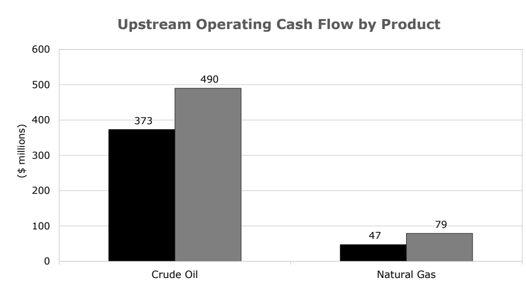
Operating Cash Flow is a non-GAAP measure used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Cash Flow is defined as revenues less purchased product, transportation and blending, operating 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)	**2016**	2015	**2016**	2015
Revenues	**3,329**	3,359	**8,737**	10,400
(Add) Deduct:				
Purchased Product	**2,004**	2,012	**5,144**	5,826
Transportation and Blending	**473**	483	**1,364**	1,509
Operating Expenses (1)	**402**	477	**1,247**	1,384
Production and Mineral Taxes	**4**	5	**9**	16
Realized (Gain) Loss on Risk Management	**(41)**	(220)	**(199)**	(417)
Operating Cash Flow	**487**	602	**1,172**	2,082

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Three Months Ended September 30, 2016 Compared With September 30, 2015



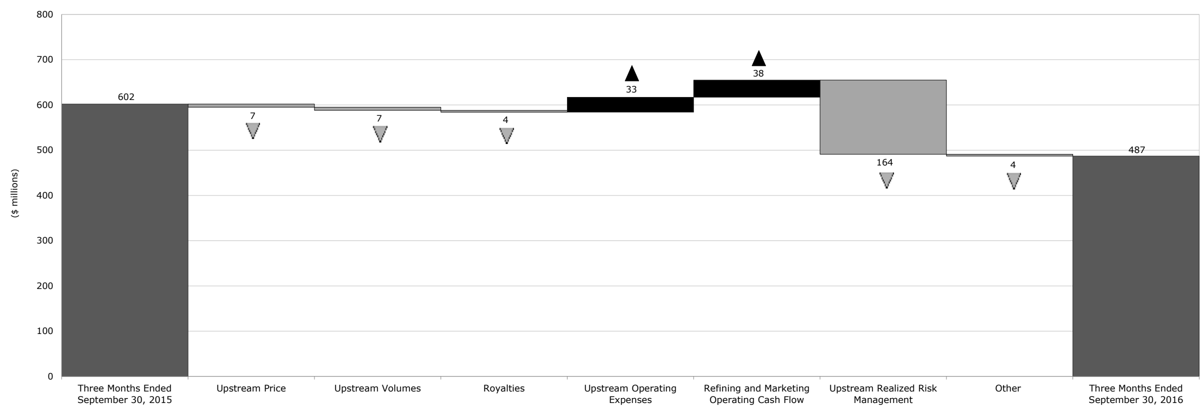


Crude oil prices and sales volumes remained relatively consistent in the third quarter of 2016 compared with 2015. Operating Cash Flow declined 19 percent in 2016 primarily due to upstream realized risk management gains of $42 million compared with gains of $206 million in 2015.

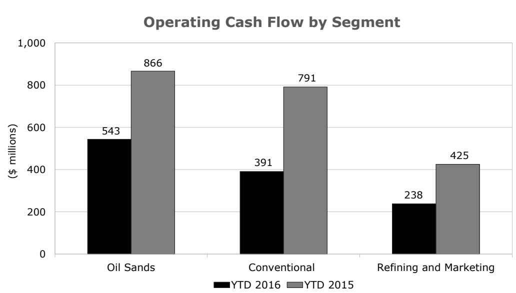
The decline in Operating Cash Flow was partially offset by:

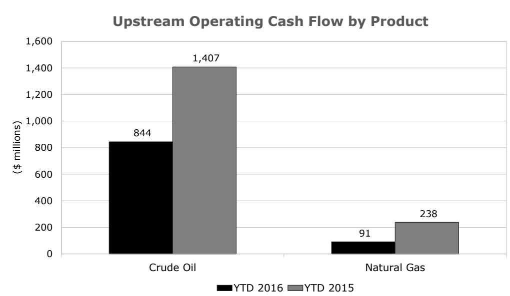
- Higher Operating Cash Flow from Refining and Marketing as a result of widening heavy and medium crude oil differentials, increased utilization rates, and lower operating expenses, partially offset by lower average market crack spreads;
- A $26 million decrease in crude oil operating expenses primarily due to lower repairs and maintenance, workforce, chemicals and electricity costs; and
- An $11 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and transportation costs.

Operating Cash Flow Variance



Nine Months Ended September 30, 2016 Compared With September 30, 2015





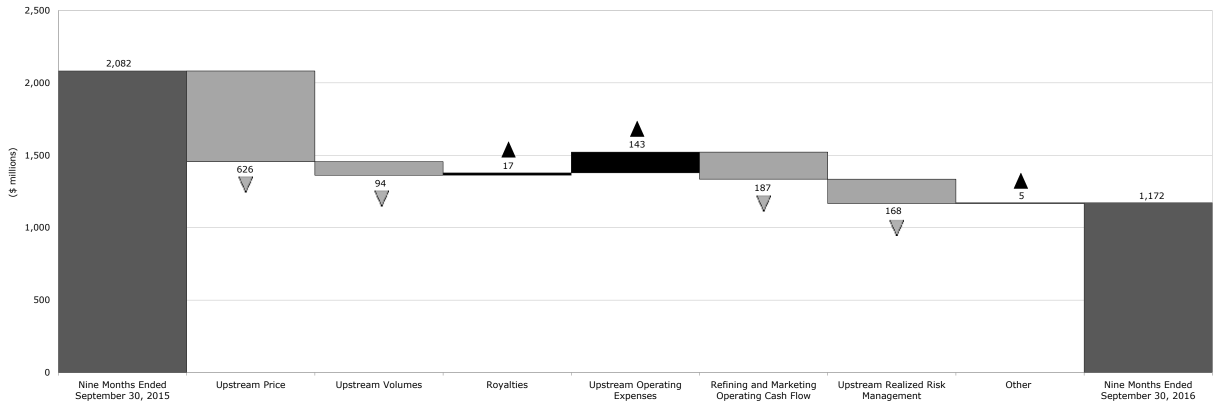
Operating Cash Flow declined 44 percent in the nine months ended September 30, 2016 compared with 2015 primarily due to:

- A 25 percent decrease in our average crude oil sales price and a 29 percent reduction in our average natural gas sales price. The steep declines in crude oil prices during the first quarter of 2016 significantly impacted our year-to-date average prices;
- Lower Operating Cash Flow from Refining and Marketing as a result of a decrease in average market crack spreads, partially offset by widening heavy and medium crude oil differentials, increased utilization rates, weakening of the Canadian dollar relative to the U.S. dollar, and improved margins on the sale of secondary products;
- Realized risk management gains of $222 million, excluding Refining and Marketing, compared with gains of $390 million in 2015; and
- A three percent decrease in our crude oil sales volumes and an 11 percent decline in our natural gas sales volumes.

These declines to Operating Cash Flow were partially offset by:

- A $144 million decrease in crude oil transportation and blending costs primarily due to lower condensate prices, partially offset by an increase in condensate volumes and higher transportation costs;
- A $123 million decrease in crude oil operating expenses primarily due to workforce reductions, decreased repairs and maintenance, chemicals, fuel, and workover activities; and
- A decline in royalties primarily due to reduced crude oil sales prices.

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.

($ millions)	Three Months Ended September 30, **2016**	2015	Nine Months Ended September 30, **2016**	2015
Cash From Operating Activities	**310**	542	**697**	1,152
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(13)**	(13)	**(59)**	(81)
Net Change in Non-Cash Working Capital	**(99)**	111	**(132)**	(183)
Cash Flow	**422**	444	**888**	1,416

In the three and nine months ended September 30, 2016, Cash Flow decreased primarily due to lower Operating Cash Flow, as discussed above, partially offset by a current income tax recovery compared with an expense in 2015.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure 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.

($ millions)	Three Months Ended September 30, **2016**	2015	Nine Months Ended September 30, **2016**	2015
Earnings (Loss), Before Income Tax	**(406)**	2,020	**(1,089)**	1,419
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (1)	**7**	(127)	**440**	169
Non-operating Unrealized Foreign Exchange (Gain) Loss (2)	**52**	437	**(343)**	852
(Gain) Loss on Divestiture of Assets	**5**	(2,379)	**6**	(2,395)
Operating Earnings (Loss), Before Income Tax	**(342)**	(49)	**(986)**	45
Income Tax Expense (Recovery)	**(106)**	(21)	**(288)**	10
Operating Earnings (Loss)	**(236)**	(28)	**(698)**	35

(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 declined in the three and nine months ended September 30, 2016 compared with 2015 primarily due to lower Cash Flow, as discussed above, higher depreciation, depletion and amortization ("DD&A") from asset impairments, and a $31 million non-cash expense on a year-to-date basis ($nil recorded in the third quarter) for office space in excess of Cenovus's current and near-term requirements, partially offset by the change in income taxes. We recorded impairment losses of $292 million and $467 million in the three and nine months ended September 30, 2016, respectively, due to a decline in long-term forward heavy crude oil and natural gas prices. Refer to the Reportable Segments section for more details.

Net Earnings

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss) for the Periods Ended September 30, 2015	**1,801**	**1,259**
Increase (Decrease) due to:		
Operating Cash Flow [(1)] [(2)]	**(115)**	**(910)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(134)**	**(271)**
Unrealized Foreign Exchange Gain (Loss)	**407**	**1,219**
Gain (Loss) on Divestiture of Assets	**(2,384)**	**(2,401)**
Expenses [(2)] [(3)]	**(13)**	**(50)**
Depreciation, Depletion and Amortization	**(186)**	**(114)**
Exploration Expense	**(1)**	**19**
Income Tax Recovery	**374**	**613**
Net Earnings (Loss) for the Periods Ended September 30, 2016	**(251)**	**(636)**

(1) Non-GAAP measure defined in this MD&A.
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.
(3) Includes general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Net Earnings for the three and nine months ended September 30, 2016 decreased primarily due to an after-tax gain in 2015 of approximately $1.9 billion from the divestiture of our royalty interest and mineral fee title lands business. In addition, the decrease was due to:

- A decline in Operating Earnings, as discussed above;
- Unrealized risk management losses of $7 million in the quarter and $440 million on a year-to-date basis (2015 – gains of $127 million and losses of $169 million, respectively); and
- A deferred income tax recovery of $111 million in the quarter and $353 million on a year-to-date basis (2015 – $228 million and $516 million, respectively).

The declines were partially offset by non-operating unrealized foreign exchange losses of $52 million in the quarter and gains of $343 million on a year-to-date basis (2015 – losses of $437 million and $852 million, respectively).

Net Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Oil Sands	**110**	272	**476**	946
Conventional	**41**	55	**114**	157
Refining and Marketing	**51**	67	**156**	159
Corporate and Eliminations	**6**	6	**21**	24
Capital Investment	**208**	400	**767**	1,286
Acquisitions	**-**	84	**11**	84
Divestitures	**(8)**	(3,329)	**(8)**	(3,345)
Net Capital Investment [(1)]	**200**	(2,845)	**770**	(1,975)

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

Capital investment in the three and nine months ended September 30, 2016 declined 48 percent and 40 percent, respectively, compared with 2015, as we reduced our spending in light of the low commodity price environment. Divestitures in the third quarter of 2016 related to non-core conventional crude oil and natural gas properties.

Oil Sands capital investment focused primarily on sustaining capital related to existing production, as well as work to complete Foster Creek phase G and Christina Lake phase F. Conventional capital investment focused on stratigraphic test well drilling for tight oil, maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn.

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

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 within the context of achieving our objectives of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position 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. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Cash Flow [1]	**422**	444	**888**	1,416
Capital Investment (Sustaining and Growth)	**208**	400	**767**	1,286
Free Cash Flow [2]	**214**	44	**121**	130
Cash Dividends	**41**	133	**124**	396
	173	(89)	**(3)**	(266)

(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 2016 to be funded from internally generated cash flow and our cash balance on hand.

REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as Grand Rapids and Telephone Lake. 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, 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. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. 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

($ millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Oil Sands	**789**	749	**1,965**	2,353
Conventional	**295**	368	**810**	1,272
Refining and Marketing	**2,245**	2,242	**5,962**	6,775
Corporate and Eliminations	**(89)**	(86)	**(245)**	(260)
	3,240	3,273	**8,492**	10,140

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, 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 2016 compared with 2015 includes:

- Decreasing our crude oil operating costs by $2 million or $0.81 per barrel to $8.65 per barrel;
- Crude oil netbacks, excluding realized risk management activities, of $15.96 per barrel (2015 – $13.65 per barrel);
- Generating Operating Cash Flow net of capital investment of $157 million, an increase of $99 million;
- Adding incremental crude oil production volumes at Foster Creek phase G, our twelfth oil sands expansion phase, which is expected to ramp-up over the next 18 months; and
- Began steam generation at Christina Lake phase F.

Oil Sands – Crude Oil

Three Months Ended September 30, 2016 Compared With September 30, 2015

Financial Results

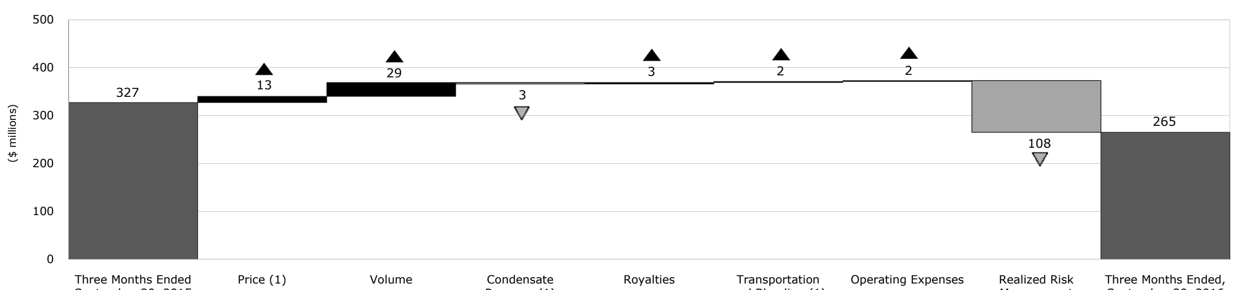
($ millions)	Three Months Ended September 30, 2016	2015
Gross Sales	**788**	749
Less: Royalties	**4**	7
Revenues	**784**	742
Expenses		
Transportation and Blending	**429**	431
Operating [(1)]	**125**	127
(Gain) Loss on Risk Management	**(35)**	(143)
Operating Cash Flow	**265**	327
Capital Investment	**107**	272
Operating Cash Flow Net of Related Capital Investment	**158**	55

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

When capital investment exceeds Operating Cash Flow from Oil Sands, it is funded through Operating Cash Flow generated by our Conventional segment as well as our cash balance on hand.

Operating Cash Flow Variance

Operating Cash Flow declined 19 percent in the third quarter of 2016 compared with 2015 primarily due to lower realized risk management gains, partially offset by higher crude oil prices and sales volumes.



(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 $31.30 per barrel, a three percent increase from 2015. The increase in our crude oil price was due to the decline in the cost of condensate used for blending, the narrowing of the WCS-Christina Dilbit Blend ("CDB") differential, and higher sales into the U.S. market, which generally secures a higher sales price, partially offset by a decrease in the WCS benchmark price.

Our bitumen sales price is influenced by the cost of condensate used in blending. Our blending ratios range from approximately 25 percent to 33 percent. As the cost of condensate decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we will see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

The WCS-CDB differential narrowed to a discount of US$2.05 per barrel (2015 – US$3.00 per barrel). In the third quarter, 88 percent of our Christina Lake production was sold as CDB (2015 – 84 percent), with the remainder sold into the WCS stream. Christina Lake production, whether sold as CDB or blended with WCS and subject to a quality equalization charge, is priced at a discount to WCS.

Production Volumes

	Three Months Ended September 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Foster Creek	**73,798**	**3%**	71,414
Christina Lake	**79,793**	**6%**	75,329
	153,591	**5%**	146,743

Production at Foster Creek for the third quarter was higher than 2015 primarily due to incremental production volumes from the phase G oil processing facility and additional wells being brought online. Ramp-up of phase G is on track and expected to take 18 months. In 2015, Foster Creek experienced strong initial production after operations were temporarily shut down in the second quarter due to a nearby forest fire.

Production from Christina Lake increased compared with the third quarter of 2015 due to additional wells being brought online, incremental production from the optimization project completed in 2015, and consistent 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. Consistent with the widening of the WCS-Condensate differential during the third quarter, the proportion of the cost of condensate recovered decreased.

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 sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The royalty calculation was based on gross revenues in 2016 and 2015.

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

	Three Months Ended September 30,	
(percent)	**2016**	2015
Foster Creek	**0.8**	0.8
Christina Lake	**1.6**	3.7

Royalties decreased $3 million in the third quarter relative to the same period in 2015 primarily due to the decline in the WTI benchmark price used in the royalty calculation, partially offset by higher crude oil sales prices and an increase in sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs decreased slightly. Blending costs declined primarily as a result of lower condensate prices partially offset by higher condensate volumes required for increased bitumen production. Our condensate costs were higher than the average benchmark price in the third quarter due to the transportation costs associated with moving the condensate from purchase point to our oil sands projects.

Transportation costs increased primarily due to tariffs associated with additional sales to the U.S. market, which generally secure a higher sales price, and shipping higher volumes due to increased production. Future production growth is expected to reduce our per-barrel transportation costs.

Transportation costs related to rail decreased, despite moving higher volumes, as we transported volumes across shorter distances. We transported an average of 15,145 gross barrels per day of crude oil by rail, consisting of 22 unit train shipments, of which 19 were loaded at our crude-by-rail terminal located in Bruderheim, Alberta (2015 – 6,642 gross barrels per day, 10 unit train shipments).

Operating

Primary drivers of our operating expenses for the third quarter were workforce, fuel, chemical costs, repairs and maintenance, and workovers. Total operating expenses decreased $2 million primarily as a result of lower repairs and maintenance activities, a decrease in property taxes and lease costs and lower electrical costs, partially offset by increased workover costs.

Per-unit Operating Expenses

	Three Months Ended September 30,		
($/bbl)	**2016**	**Percent Change**	2015
Foster Creek			
Fuel	**2.44**	**(8)%**	2.65
Non-fuel [1]	**7.19**	**(17)%**	8.62
Total	**9.63**	**(15)%**	11.27
Christina Lake			
Fuel	**2.14**	**(7)%**	2.30
Non-fuel [1]	**5.58**	**1%**	5.50
Total	**7.72**	**(1)%**	7.80
Total	**8.65**	**(9)%**	9.46

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

At Foster Creek, fuel costs decreased primarily due to the decline in natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Higher production; and
- Lower workforce costs.

At Christina Lake, fuel costs declined due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses remained relatively consistent with 2015.

Operating Netbacks

	Foster Creek		Christina Lake	
	Three Months Ended September 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price [1]	**33.61**	33.35	**29.11**	27.46
Royalties	**0.19**	0.20	**0.41**	0.83
Transportation and Blending [1]	**8.38**	8.50	**4.49**	5.00
Operating Expenses [2]	**9.63**	11.27	**7.72**	7.80
Netback Excluding Realized Risk Management	**15.41**	13.38	**16.49**	13.83
Realized Risk Management	**2.37**	11.93	**2.38**	9.41
Netback Including Realized Risk Management	**17.78**	25.31	**18.87**	23.24

(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 $22.82 per barrel (2015 – $24.20 per barrel) for Foster Creek, and $23.93 per barrel (2015 – $26.42 per barrel) for Christina Lake.

(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Risk Management

Risk management activities in the third quarter resulted in realized gains of $35 million (2015 – $143 million), consistent with our contract prices exceeding average benchmark prices.

Nine Months Ended September 30, 2016 Compared With September 30, 2015

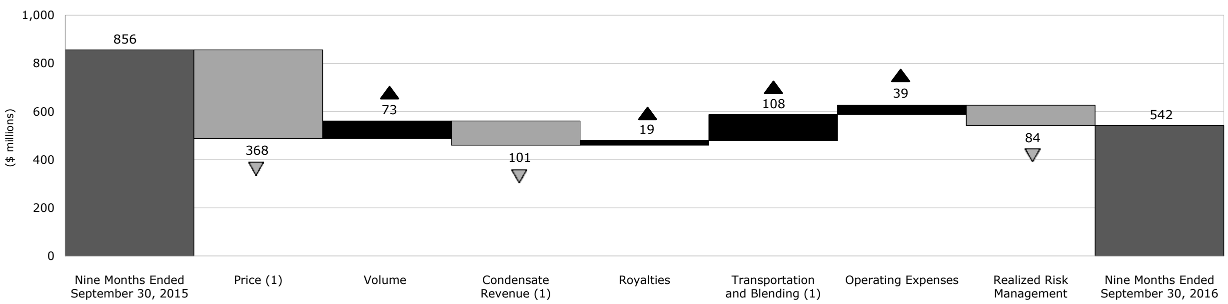
Financial Results

($ millions, unless otherwise noted)	Nine Months Ended September 30, 2016	2015
Gross Sales	**1,960**	2,356
Less: Royalties	**7**	26
Revenues	**1,953**	2,330
Expenses		
Transportation and Blending	**1,228**	1,336
Operating [(1)]	**348**	387
(Gain) Loss on Risk Management	**(165)**	(249)
Operating Cash Flow	**542**	856
Capital Investment	**472**	945
Operating Cash Flow Net of Related Capital Investment	**70**	(89)

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

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.

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

First quarter crude oil sales prices, which were approximately 65 percent lower than prices in the second and third quarter, had a significant impact on our year-to-date average prices. For the nine months ended September 30, 2016, our average crude oil sales price was $24.28 per barrel, a decrease of 28 percent from 2015. The decline in our crude oil sales price was consistent with the decrease in the WCS and CDB benchmark prices, partially offset by a decline in the cost of condensate used in blending, the weakening of the Canadian dollar relative to the U.S. dollar, and increased sales into the U.S. market, which generally secure a higher sales price.

In the nine months ended September 30, 2016, 89 percent of our Christina Lake production was sold as CDB (2015 – 86 percent), with the remainder sold into the WCS stream.

Production Volumes

(barrels per day)	Nine Months Ended September 30, 2016	Percent Change	2015
Foster Creek	**66,435**	**1%**	65,906
Christina Lake	**78,321**	**5%**	74,720
	144,756	**3%**	140,626

On a year-to-date basis, production rose at Foster Creek primarily due to incremental production volumes at the phase G facility and additional wells being brought online. In 2015, production decreased by approximately 3,500 barrels per day due to a nearby forest fire which resulted in the temporary shutdown of operations in the second quarter.

Production from Christina Lake increased in the nine months ended September 30, 2016 due to increased production from additional wells, incremental production from the optimization project completed in 2015, and consistent performance of our facilities.

Royalties

Effective Royalty Rates

(percent)	Nine Months Ended September 30, 2016	2015
Foster Creek	**0.5**	2.1
Christina Lake	**1.4**	3.0

Royalties decreased $19 million compared with 2015. At Foster Creek, low crude oil sales prices and the true-up of the 2015 royalty calculation decreased the overall royalty rate in 2016. In 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. Excluding the credit, the effective royalty rate in 2015 for Foster Creek would have been 3.6 percent. The royalty calculation was based on gross revenues in 2016 and 2015.

The Christina Lake royalty rate decreased in 2016 as a result of lower sales prices and the decline in the WTI benchmark price.

Expenses

Transportation and Blending

Transportation and blending costs decreased $108 million or eight percent. Blending costs declined primarily due to lower condensate prices, partially offset by higher condensate volumes required for increased bitumen production. Our condensate costs exceeded the average benchmark price in 2016 primarily due to the transportation costs associated with moving the condensate from purchase point to our oil sands projects.

Transportation costs increased primarily due to tariffs from additional sales to the U.S. market, which generally secure a higher sales price, and shipping higher volumes due to increased production. Future production growth is expected to reduce our per-barrel transportation costs.

Transportation costs related to rail decreased, despite moving higher volumes, as we transported volumes across shorter distances. We transported an average of 10,212 gross barrels per day of crude oil by rail, consisting of 45 unit train shipments, of which 42 unit trains were loaded at our crude-by-rail terminal, located in Bruderheim, Alberta (2015 – 7,889 gross barrels per day, 36 unit train shipments).

Operating

Primary drivers of our operating expenses for the nine months ended September 30, 2016 were workforce, fuel, workovers, chemicals, and repairs and maintenance. Total operating expenses decreased $39 million primarily as a result of a decline in repairs and maintenance activities, lower natural gas prices that reduced fuel costs, and workforce reductions.

Per-unit Operating Expenses

($/bbl)	Nine Months Ended September 30, 2016	Percent Change	2015
Foster Creek			
Fuel	**2.20**	**(21)%**	2.78
Non-fuel [(1)]	**8.32**	**(18)%**	10.14
Total	**10.52**	**(19)%**	12.92
Christina Lake			
Fuel	**1.85**	**(17)%**	2.22
Non-fuel [(1)]	**5.39**	**(8)%**	5.86
Total	**7.24**	**(10)%**	8.08
Total	**8.74**	**(15)%**	10.32

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

At Foster Creek, fuel costs decreased primarily due to the decline in natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses declined primarily due to:

- Lower repairs and maintenance costs from focusing on critical operational activities;
- Higher production;
- Workforce reductions; and
- A decline in workover expenses due to reduced well maintenance activity.

At Christina Lake, fuel costs declined due to lower natural gas prices partially offset by an increase in fuel consumption on a per-barrel basis. Non-fuel operating expenses decreased primarily due to:

- Higher production; and
- Lower chemical costs due to supply chain initiatives.

These decreases were offset by higher workover costs due to more pump changes.

Operating Netbacks

($/bbl)	Foster Creek 2016	Foster Creek 2015	Christina Lake 2016	Christina Lake 2015
	Nine Months Ended September 30,			
Price [1]	**26.97**	36.58	**22.01**	30.92
Royalties	**0.10**	0.59	**0.25**	0.80
Transportation and Blending [1]	**9.43**	8.95	**4.89**	4.49
Operating Expenses [2]	**10.52**	12.92	**7.24**	8.08
Netback Excluding Realized Risk Management	**6.92**	14.12	**9.63**	17.55
Realized Risk Management	**4.37**	7.36	**3.95**	6.01
Netback Including Realized Risk Management	**11.29**	21.48	**13.58**	23.56

(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 was $24.43 per barrel (2015 – $27.94 per barrel) for Foster Creek, and $25.52 per barrel (2015 – $30.23 per barrel) for Christina Lake.*

(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Risk Management

Risk management activities for the nine months ended September 30, 2016 resulted in realized gains of $165 million (2015 – $249 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Natural Gas

Oil Sands include our natural gas operations in northeastern Alberta. 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, 2016, net of internal usage, was 18 MMcf per day and 17 MMcf per day, respectively (2015 – 19 MMcf per day and 20 MMcf per day, respectively).

Operating Cash Flow from our Oil Sands natural gas production was $3 million in the third quarter (2015 – $3 million) and $4 million on a year-to-date basis (2015 – $7 million), declining primarily due to lower natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended September 30, 2016	Three Months Ended September 30, 2015	Nine Months Ended September 30, 2016	Nine Months Ended September 30, 2015
Foster Creek	**54**	96	**211**	318
Christina Lake	**47**	147	**222**	515
	101	243	**433**	833
Narrows Lake	**1**	12	**6**	41
Telephone Lake	**3**	4	**13**	19
Grand Rapids	**-**	6	**5**	32
Other [1]	**5**	7	**19**	21
Capital Investment [2]	**110**	272	**476**	946

(1) *Includes new resource plays and Athabasca natural gas.*

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

Existing Projects

Capital investment at Foster Creek and Christina Lake in 2016 focused on sustaining capital related to existing production and drilling stratigraphic test wells in the first quarter to help identify well pad locations for sustaining wells and near-term expansion phases. Capital was also invested in 2016 to complete Foster Creek phase G and progress Christina Lake phase F. Capital investment at Foster Creek and Christina Lake declined in the third quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment. Lower capital investment at Christina Lake is also attributable to the completion of the optimization project in 2015.

Capital investment at Narrows Lake in 2016 focused on detailed engineering. Capital investment was lower in 2016 compared with 2015 due to the suspension of construction at Narrows Lake.

Emerging Projects

Telephone Lake capital investment declined in 2016 in response to the current low commodity price environment. In 2016, Telephone Lake capital investment focused on front-end engineering work for the central processing facility.

Capital investment at Grand Rapids decreased in 2016 as spending was limited to the wind down of the SAGD pilot. In 2015, a third pilot well pair was completed at Grand Rapids.

Drilling Activity [1]

	Gross Stratigraphic Test Wells [2]		Gross Production Wells [3]	
	Nine Months Ended September 30,			
	2016	2015	**2016**	2015
Foster Creek	**95**	122	**18**	21
Christina Lake	**97**	36	**24**	67
	192	158	**42**	88
Grand Rapids	**-**	-	**-**	1
Other	**5**	-	**-**	-
	197	158	**42**	89

(1) We did not drill any gross service wells in the nine months ended September 30, 2016 (2015 – seven 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 2016, no wells were drilled using our SkyStrat™ drilling rig (2015 – seven gross wells).
(3) SAGD well pairs are counted as a single producing well.

Future Capital Investment

We have adopted a more moderate and staged approach to future oil sands expansions due to the low commodity price environment.

Existing Projects

Foster Creek is currently producing from phases A through G. Incremental production from phase G was added in the third quarter and ramp-up is expected to take approximately 18 months. We expect phase G to add initial design capacity of 30,000 gross barrels per day. Capital investment for 2016 is forecast to be between $250 million and $270 million, focused on sustaining capital related to existing production and expansion phase G. 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 barrels per day phase.

Christina Lake is producing from phases A through E. Commissioning of the phase F facility, including cogeneration, is underway. We began steam generation in the third quarter and expect production to be added in the fourth quarter of 2016. We anticipate adding gross production capacity of 50,000 barrels per day from phase F with ramp-up expected to take approximately twelve months. Capital investment for 2016 is forecast to be between $265 million and $285 million, focused on sustaining capital related to existing production and expansion phase F. Construction work on phase G was deferred in 2015 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 received regulatory approval in December 2015 for expansion phase H, a 50,000 gross barrels per day phase.

Capital investment at Narrows Lake in 2016 is forecast to be between $5 million and $10 million, focusing on phase A detailed engineering and equipment preservation related to the suspension of construction.

Emerging Projects

Capital investment for our new resource plays is forecast to be between $35 million and $45 million in 2016.

Depreciation, Depletion & Amortization

We deplete crude oil and natural gas properties on a unit-of-production basis over 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 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, 2015
Upstream Property, Plant and Equipment	**12,627**
Estimated Future Development Capital	**19,671**
Total Estimated Upstream Cost Base	**32,298**
Total Proved Reserves (MMBOE)	**2,546**
Implied Depletion Rate ($/BOE)	**12.69**

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 $13.50 and $14.50 per BOE. Amounts related to assets under construction, which would be included in the total upstream cost base and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets that are depreciated on a straight-line basis. As such, our actual depletion will differ from depletion calculated by applying the above implied depletion rate. Further information on our accounting policy for DD&A is included in our notes to the Consolidated Financial Statements.

In the third quarter, DD&A remained relatively flat. On a year-to-date basis, DD&A declined $23 million primarily due to lower DD&A rates, partially offset by higher sales volumes and impairment losses. The impairment losses of $16 million related to preliminary project engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount.

The average depletion rate was approximately $11.55 per barrel compared with $11.65 per barrel in 2015 as the impact of proved reserves additions offset higher PP&E and future development expenditures. Future development costs, which compose approximately 60 percent of the depletable base, increased due to expansion of the development area at Christina Lake.

CONVENTIONAL

Our Conventional operations include dependable 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 that uses polymer flood and waterflood technology and emerging tight oil assets in Alberta. 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.

Significant developments that impacted our Conventional segment in the third quarter of 2016 compared with 2015 includes:

- Generating Operating Cash Flow net of capital investment of $111 million, a decrease of 41 percent;
- Reducing our crude oil operating costs by $24 million or $2.56 per barrel;
- Crude oil and natural gas netbacks, excluding realized risk management activities, of $20.63 per barrel (2015 – $19.06 per barrel) and $1.25 per Mcf (2015 – $1.66 per Mcf), respectively;
- Crude oil production of 54,481 barrels per day, a decrease of 14 percent; and
- Recording impairment losses of $210 million and $65 million, associated with our Northern Alberta and Suffield cash generating units (“CGU”), respectively, due to the decline in long-term forward heavy crude oil and natural gas prices.

Conventional – Crude Oil

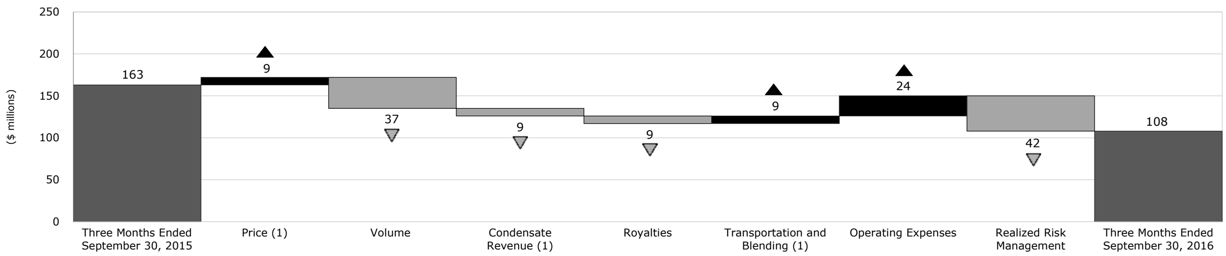
Three Months Ended September 30, 2016 Compared With September 30, 2015

Financial Results

($ millions)	Three Months Ended September 30, 2016	2015
Gross Sales	**242**	279
Less: Royalties	**32**	23
Revenues	**210**	256
Expenses		
Transportation and Blending	**40**	49
Operating (1)	**65**	89
Production and Mineral Taxes	**4**	4
(Gain) Loss on Risk Management	**(7)**	(49)
Operating Cash Flow	**108**	163
Capital Investment	**39**	52
Operating Cash Flow Net of Related Capital Investment	**69**	111

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 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

Our Conventional crude oil assets produce a diverse spectrum of crude oils, ranging from heavy oil, which secures a price based on the WCS benchmark, to light oil, which secures a price closer to the WTI benchmark.

Our crude oil sales price averaged $44.24 per barrel in the third quarter, a four percent increase from 2015, due to the decline in the cost of condensate used for blending our heavy oil, partially offset by lower crude oil benchmark prices, adjusted for applicable differentials. As the cost of condensate decreases relative to the price of blended crude oil, our heavy oil sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we will see some benefit in our heavy oil sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

	Three Months Ended September 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Heavy Oil	**28,096**	**(17)%**	33,997
Light and Medium Oil	**25,311**	**(11)%**	28,491
NGLs	**1,074**	**(10)%**	1,191
	54,481	**(14)%**	63,679

Crude oil production decreased due to expected natural declines and the sale of our royalty interest and mineral fee title lands business. Divested assets contributed an average of 1,250 barrels per day in the third quarter of 2015.

Condensate

The heavy oil currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market. Our blending ratios range from approximately 10 percent to 16 percent. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the widening of the WCS-Condensate differential during the third quarter, the proportion of the cost of condensate recovered decreased.

Royalties

Royalties increased in the third quarter primarily due to lower allowable operating and capital costs at Pelican Lake and Weyburn, additional royalty burdens resulting from the sale of our royalty interest and mineral fee title lands business in 2015, and higher sales prices, partially offset by a decrease in sales volumes. In the third quarter, the effective crude oil royalty rate for our Conventional properties was 15.8 percent (2015 – 10.1 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 sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The Pelican Lake crown royalty calculation is based on net profits.

In the third quarter of 2016, production and mineral taxes remained flat as the sale of our royalty interest and mineral fee title lands business in 2015 was offset by the increase in crude oil prices.

Expenses

Transportation and Blending

Transportation and blending costs decreased $9 million. Blending costs declined due to a decrease in condensate volumes, consistent with lower production, and a decline in condensate prices.

Transportation charges were flat due to a decline in sales volumes offset by higher costs associated with optimizing our sales and additional costs due to pipeline capacity commitments in excess of our current production.

Operating

Primary drivers of our operating expenses in the third quarter of 2016 were workforce, workovers, electricity, and property taxes and lease costs. Operating costs declined 17 percent to $12.89 per barrel primarily due to:

- Lower costs due to workforce reductions undertaken in late 2015 and early 2016;
- Lower chemical costs associated with reduced polymer consumption;
- A decrease in repairs and maintenance and workover costs as a result of focusing on critical activities and achieving operational efficiencies; and
- Reduced electricity costs as a result of a decline in prices and a decrease in consumption.

These decreases were partially offset by lower production.

Operating Netbacks

	Heavy Oil		Light and Medium	
	Three Months Ended September 30,			
($/bbl)	**2016**	2015	**2016**	2015
Price [1]	**40.50**	37.09	**48.97**	49.57
Royalties	**3.97**	1.73	**8.91**	7.02
Transportation and Blending [1]	**4.86**	3.36	**2.71**	2.88
Operating Expenses [2]	**12.43**	15.59	**13.94**	15.92
Production and Mineral Taxes	**0.01**	0.07	**1.48**	1.60
Netback Excluding Realized Risk Management	**19.23**	16.34	**21.93**	22.15
Realized Risk Management	**1.50**	9.03	**1.47**	8.80
Netback Including Realized Risk Management	**20.73**	25.37	**23.40**	30.95

(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 $8.31 per barrel (2015 – $9.56 per barrel).*
(2) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Risk Management

Risk management activities for the third quarter resulted in realized gains of $7 million (2015 – $49 million), consistent with our contract prices exceeding average benchmark prices.

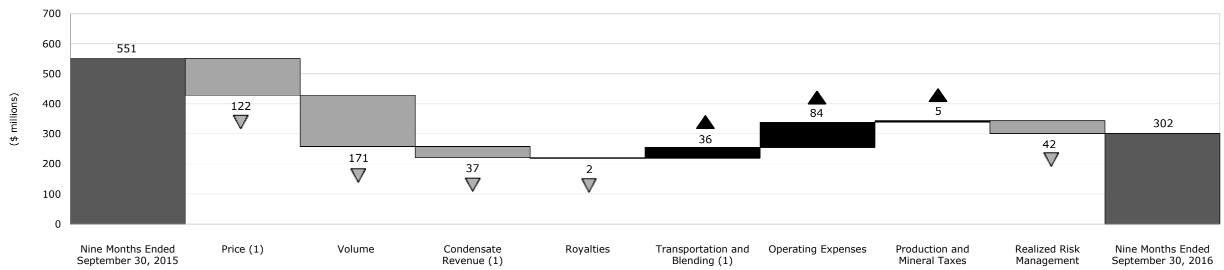
Nine Months Ended September 30, 2016 Compared With September 30, 2015

Financial Results

	Nine Months Ended September 30,	
($ millions)	**2016**	2015
Gross Sales	**670**	1,000
Less: Royalties	**80**	78
Revenues	**590**	922
Expenses		
Transportation and Blending	**124**	160
Operating [1]	**213**	297
Production and Mineral Taxes	**9**	14
(Gain) Loss on Risk Management	**(58)**	(100)
Operating Cash Flow	**302**	551
Capital Investment	**108**	148
Operating Cash Flow Net of Related Capital Investment	**194**	403

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 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

Our average crude oil sales price decreased 17 percent to $38.49 per barrel consistent with the decline in crude oil benchmark prices, adjusted for applicable differentials.

Production Volumes

	Nine Months Ended September 30,		
(barrels per day)	**2016**	**Percent Change**	2015
Heavy Oil	**29,276**	**(18)%**	35,739
Light and Medium Oil	**26,200**	**(18)%**	31,787
NGLs	**1,027**	**(20)%**	1,286
	56,503	**(18)%**	68,812

Production was lower primarily due to expected natural declines and the sale of our royalty interest and mineral fee title lands business in 2015. Divested assets contributed an average of 3,415 barrels per day for the nine months ended September 30, 2015.

Royalties

Royalties increased slightly due to lower allowable operating and capital costs at Pelican Lake and Weyburn, additional royalty burdens resulting from the sale of our royalty interest and mineral fee title lands business in 2015, partially offset by a reduction in sales volumes and lower sales prices. For the nine months ended September 30, 2016, the effective crude oil royalty rate for our Conventional properties was 14.9 percent (2015 – 9.3 percent). The Pelican Lake crown royalty calculation was based on net profits in both 2016 and 2015.

Production and mineral taxes declined on a year-to-date basis, consistent with lower crude oil prices in 2016, and due to the sale of our royalty interest and mineral fee title lands business in 2015.

Expenses

Transportation and Blending

Transportation and blending costs decreased $36 million. Blending costs declined primarily due to a reduction in condensate volumes, consistent with lower production, and a decrease in condensate prices.

Transportation charges were lower largely due to a decline in sales volumes, partially offset by higher transportation costs associated with optimizing our sales and additional costs due to pipeline capacity commitments in excess of our current production.

Operating

Primary drivers of our operating expenses for the nine months ended September 30, 2016 were workforce costs, workover activities, electricity, property taxes and lease costs, repairs and maintenance, and chemical consumption. Operating expenses declined $84 million or $1.85 per barrel. The per-unit decline was primarily due to:

- A decrease in repairs and maintenance and workover costs due to a focus on critical operational activities;
- Lower chemical costs associated with reduced polymer consumption;
- Workforce reductions; and
- Lower electricity costs as a result of a decrease in consumption and a decline in prices.

These decreases were partially offset by lower production.

Operating Netbacks

($/bbl)	Heavy Oil Nine Months Ended September 30, **2016**	 2015	Light and Medium **2016**	 2015
Price [1]	**34.18**	42.01	**43.66**	52.13
Royalties	**3.06**	3.18	**7.50**	5.30
Transportation and Blending [1]	**4.50**	3.29	**2.74**	2.94
Operating Expenses [2]	**12.94**	16.13	**15.52**	15.96
Production and Mineral Taxes	**-**	0.06	**1.15**	1.60
Netback Excluding Realized Risk Management	**13.68**	19.35	**16.75**	26.33
Realized Risk Management	**3.98**	5.50	**3.88**	5.66
Netback Including Realized Risk Management	**17.66**	24.85	**20.63**	31.99

(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 $9.58 per barrel (2015 – $11.21 per barrel).
(2) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Risk Management

Risk management activities for the nine months ended September 30, 2016 resulted in realized gains of $58 million (2015 – $100 million), consistent with our contract prices exceeding average benchmark prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended September 30, **2016**	2015	Nine Months Ended September 30, **2016**	2015
Gross Sales	**86**	113	**221**	346
Less: Royalties	**3**	5	**8**	8
Revenues	**83**	108	**213**	338
Expenses				
Transportation and Blending	**4**	3	**12**	12
Operating	**35**	41	**113**	131
Production and Mineral Taxes	**-**	1	**-**	2
(Gain) Loss on Risk Management	**-**	(13)	**1**	(38)
Operating Cash Flow	**44**	76	**87**	231
Capital Investment	**2**	3	**6**	9
Operating Cash Flow Net of Related Capital Investment	**42**	73	**81**	222

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

Three and Nine Months Ended September 30, 2016 Compared With September 30, 2015

Revenues

Pricing

In the three and nine months ended September 30, 2016, our average natural gas sales price decreased 17 percent to $2.49 per Mcf and 29 percent to $2.11 per Mcf, respectively. This is consistent with the decline in the AECO benchmark price.

Production

Production decreased by nine percent to 374 MMcf per day in the third quarter and by 11 percent to 382 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. Divested assets produced 6 MMcf and 13 MMcf per day, respectively, in the three and nine months ended September 30, 2015.

Royalties

Royalties remained relatively consistent as additional royalty burdens due to the sale of our royalty interest and mineral fee title lands business were offset by lower prices and production declines. The average royalty rate in the third quarter was 4.5 percent (2015 – 4.1 percent) and 4.4 percent (2015 – 2.3 percent) on a year-to-date basis.

Expenses

Transportation

In the three and nine months ended September 30, 2016, transportation costs were consistent with 2015. Cost reductions due to the decline in sales volumes were offset by additional charges from a true-up of 2015 transportation contracts.

Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2016 were property taxes and lease costs, and workforce. Operating expenses in the three and nine months ended September 30, 2016 decreased by $6 million and $18 million, respectively, primarily due to lower workforce costs, a reduction in repairs and maintenance, and a decline in electricity costs due to lower pricing.

Risk Management

Risk management activities resulted in an impact of $nil in the third quarter and realized losses of $1 million on a year-to-date basis (2015 – realized gains of $13 million in the third quarter and $38 million on a year-to-date basis), consistent with average benchmark prices relative to our contract prices.

Conventional – Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Heavy Oil	**11**	14	**34**	46
Light and Medium Oil	**28**	38	**74**	102
Natural Gas	**2**	3	**6**	9
Capital Investment (1)	**41**	55	**114**	157

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

Capital investment in 2016 was primarily related to stratigraphic test well drilling for tight oil, maintenance capital and spending for our CO_2 enhanced oil recovery project at Weyburn. Capital investment declined in 2016 primarily due to spending reductions on crude oil activities in response to the low commodity price environment.

Drilling Activity

	Nine Months Ended September 30,	
(net wells, unless otherwise stated)	**2016**	2015
Crude Oil	**1**	15
Recompletions	**84**	498
Gross Stratigraphic Test Wells	**27**	-

Drilling activity in 2016 focused on stratigraphic test well drilling for tight oil and natural gas recompletions performed to optimize production.

Future Capital Investment

We are taking a more moderate approach to developing our conventional crude oil opportunities due to the low commodity price environment. 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 2016 crude oil capital investment forecast is between $150 million and $175 million with spending plans mainly focused on maintaining and optimizing current production volumes.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over 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 proved reserves.

Conventional DD&A increased $188 million in the third quarter and $132 million on a year-to-date basis, compared with 2015, primarily due to impairment losses, partially offset by a decline in sales volumes and lower DD&A rates.

In the third quarter of 2016, we determined that the carrying amounts of the Northern Alberta and Suffield CGUs exceeded their recoverable amounts due to a decline in long-term forward heavy crude oil and natural gas prices, resulting in impairment losses of $210 million and $65 million, respectively. We previously impaired the Northern Alberta CGU by $170 million, due to a decline in long-term forward crude oil prices at March 31, 2016. Year-to-date, impairment losses in 2016 were $445 million.

The average depletion rate decreased approximately 20 percent in 2016 as the impact of lower proved reserves due to the slowdown of our development plans was more than offset by lower PP&E. PP&E declined, in part, from an impairment loss of $184 million associated with our Northern Alberta CGU recorded at December 31, 2015 and a decrease in estimated decommissioning costs. Future development costs, which compose approximately 40 percent of the depletable base, declined from 2015 due to minimal capital investment planned at Pelican Lake in the near term.

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 positions 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.

This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In the three and nine months ended September 30, 2016, we loaded an average of 15,186 barrels per day and 12,487 barrels per day, consisting of 20 and 45 unit trains, respectively.

Refinery Operations [1]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	**2016**	2015
Crude Oil Capacity (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**463**	394	**452**	424
Heavy Crude Oil	**241**	186	**237**	202
Light/Medium	**222**	208	**215**	222
Refined Products (Mbbls/d)	**494**	414	**479**	448
Gasoline	**235**	208	**235**	228
Distillate	**152**	131	**148**	141
Other	**107**	75	**96**	79
Crude Utilization (percent)	**101**	86	**98**	92

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

On a 100-percent basis, our refineries have total processing capacity of approximately 460,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. We also have processing capacity of 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows us to economically integrate our heavy crude oil production. Processing less expensive crude oil creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. 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. Our crude utilization represents the percentage of total crude oil processed in our refineries relative to the total capacity.

Crude oil runs and refined product output increased in the third quarter of 2016 compared with 2015 due to consistent performance at the Wood River and Borger refineries. In September, unplanned maintenance was performed at the Borger refinery. As a result, a portion of the maintenance originally scheduled for October was started in the third quarter. In the third quarter of 2015, crude utilization was lower due to unplanned process unit outages at the Borger refinery for most of July and the start of a planned turnaround at the Wood River refinery.

On a year-to-date basis, crude oil runs and refined product output increased. Strong performance at both of the refineries was slightly offset by planned and unplanned maintenance at the Wood River and Borger refineries in the first quarter of 2016, and unplanned maintenance at the Borger refinery in September. In 2015, we experienced unplanned outages at the Borger refinery and planned turnarounds at both refineries. Higher heavy crude oil volumes were processed in 2016 primarily due to the optimization of our total crude input slate.

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2016**	2015	**2016**	2015
Revenues	**2,245**	2,242	**5,962**	6,775
Purchased Product	**2,004**	2,012	**5,144**	5,826
Gross Margin	**241**	230	**818**	949
Expenses				
Operating [1]	**172**	214	**557**	551
(Gain) Loss on Risk Management	**1**	(14)	**23**	(27)
Operating Cash Flow	**68**	30	**238**	425
Capital Investment	**51**	67	**156**	159
Operating Cash Flow Net of Related Capital Investment	**17**	(37)	**82**	266

(1) Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.

Gross Margin

Our realized crack spreads are affected by many factors, such as the variety of feedstock crude oil, 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 three months ended September 30, 2016, our refining gross margin increased, compared with 2015, primarily due to wider heavy and medium crude oil differentials creating a feedstock cost advantage, and higher crude utilization rates by 15 percent. This was partially offset by lower average market crack spreads as a result of higher global refined product inventory and a narrower Brent-WTI differential.

In the nine months ended September 30, 2016, our refining gross margin declined primarily due to lower average market crack spreads. This was partially offset by:

- Wider heavy and medium crude oil differentials;
- Higher utilization rates;
- A weaker Canadian dollar relative to the U.S. dollar which had a positive impact of approximately $36 million on our refining gross margin; and
- Improved margins on the sale of secondary products, such as coke, asphalt and sulfur, due to lower overall feedstock costs.

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 three and nine months ended September 30, 2016, the cost of our RINs were $80 million and $209 million, respectively (2015 – $27 million and $120 million, respectively). The increase is consistent with the ethanol RINs benchmark price which increased 130 percent and 40 percent in the three and nine months ended September 30, 2016, respectively.

Revenues from third-party crude oil and natural gas sales undertaken by the marketing group in the third quarter increased 41 percent from 2015. Higher purchased crude oil and natural gas volumes, and an increase in our crude oil sales price was partially offset by lower natural gas sales prices. On a year-to-date basis, revenues from third-party sales increased seven percent compared with 2015 due to higher purchased crude oil and natural gas volumes, partially offset by lower sales prices.

Operating Expense

Primary drivers of operating expenses in the third quarter of 2016 and on a year-to-date basis were labour, maintenance and utilities. Reported operating expenses declined in the third quarter primarily due to a decline in maintenance activities associated with fewer unplanned outages and planned turnarounds. On a year-to-date basis, operating expenses increased primarily due to the weakening of the Canadian dollar relative to the U.S. dollar, partially offset by a reduction in maintenance activities as a result of the consistent performance at both of our refineries, and a decline in utility costs.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended September 30, **2016**	2015	Nine Months Ended September 30, **2016**	2015
Wood River Refinery	**33**	47	**108**	108
Borger Refinery	**16**	19	**42**	49
Marketing	**2**	1	**6**	2
	51	67	**156**	159

Capital expenditures in 2016 focused on the debottlenecking project at Wood River, capital maintenance, projects to improve our refinery reliability and safety, and environmental initiatives. In the third quarter of 2016, the Wood River debottlenecking project was successfully completed. As a result, our blended heavy crude oil processing capability has increased by 18,000 gross barrels per day. The amount of heavy crude oil processed continues to be dependent on the optimization of our total input slate.

In 2016, we expect to invest between $230 million and $255 million mainly related to maintenance, reliability and environmental initiatives, as well as the debottlenecking project at Wood River.

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, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A increased by $3 million in the third quarter of 2016 and $17 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 power purchase contract and interest rate swaps. In the third quarter of 2016, our risk management activities resulted in $7 million of unrealized losses (2015 – unrealized gains of $127 million). On a year-to-date basis, we had $440 million of unrealized losses (2015 – $169 million). The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, financing and research costs.

($ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	**2016**	2015
General and Administrative [1]	**71**	78	**225**	226
Finance Costs	**122**	122	**368**	359
Interest Income	**(27)**	(6)	**(45)**	(20)
Foreign Exchange (Gain) Loss, Net	**45**	417	**(338)**	832
Research Costs	**5**	6	**30**	20
(Gain) Loss on Divestiture of Assets	**5**	(2,379)	**6**	(2,395)
Other (Income) Loss, Net	**5**	(1)	**7**	1
	226	(1,763)	**253**	(977)

(1) *Employee long-term incentive costs in prior periods were reclassified from operating expenses to general and administrative costs to conform to the presentation adopted for the year ended December 31, 2015.*

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2016 were workforce, office rent and information technology costs. General and administrative expenses decreased in the third quarter and on a year-to-date basis by $7 million and $1 million, respectively. Savings from workforce reductions, lower information technology costs and reduced discretionary spending were partially offset by severance costs recorded in the second quarter of 2016 related to the workforce reductions implemented in April 2016. Additionally, on a year-to-date basis a non-cash expense of $31 million was recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs remained consistent in the third quarter and increased by $9 million on a year-to-date basis, compared with 2015. The Canadian dollar relative to the U.S. dollar remained relatively consistent in the third quarter of 2016 compared with 2015 and weakened on a year-to-date basis which increased reported interest expense on our U.S. dollar denominated debt.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2016 was 5.3 percent (2015 – 5.3 percent).

Foreign Exchange

($ millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2016	2015	**2016**	2015
Unrealized Foreign Exchange (Gain) Loss	**50**	457	**(341)**	878
Realized Foreign Exchange (Gain) Loss	**(5)**	(40)	**3**	(46)
	45	417	**(338)**	832

The majority of unrealized foreign exchange gains on a year-to-date basis resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar, relative to the U.S. dollar, at September 30, 2016 was slightly weaker compared with June 30, 2016, resulting in unrealized losses of $50 million in the third quarter. The Canadian dollar, relative to the U.S. dollar, strengthened by five percent from December 31, 2015 to September 30, 2016 resulting in year-to-date unrealized gains of $341 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 was $14 million (2015 – $20 million) and $50 million on a year-to-date basis (2015 – $62 million).

Income Tax

($ millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Current Tax				
Canada	**(44)**	451	**(101)**	686
U.S.	**-**	(4)	**1**	(10)
Total Current Tax Expense (Recovery)	**(44)**	447	**(100)**	676
Deferred Tax Expense (Recovery)	**(111)**	(228)	**(353)**	(516)
	(155)	219	**(453)**	160

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

($ millions)	Nine Months Ended September 30, 2016	2015
Earnings (Loss) Before Income Tax	**(1,089)**	1,419
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(294)**	370
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(38)**	(15)
Non-Deductible Stock-Based Compensation	**6**	7
Non-Taxable Capital (Gains) Losses	**(46)**	113
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(46)**	113
Adjustments Arising From Prior Year Tax Filings	**(48)**	(13)
Recognition of Capital Losses	**-**	(149)
Recognition of U.S. Tax Basis	**-**	(385)
Change in Statutory Rate	**-**	158
Other	**13**	(39)
Total Tax (Recovery)	**(453)**	160
Effective Tax Rate	**41.6%**	11.3%

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.

In the three and nine months ended September 30, 2016, we incurred losses for income tax purposes which will be carried back to recover income taxes previously paid in Canada or recognized as a deferred tax recovery. In the third quarter of 2016, a current income tax recovery was recognized related to prior year adjustments. In the third quarter of 2015, current income tax expense included $391 million attributable to the sale of our royalty interest and mineral fee title lands.

In the three and nine months ended September 30, 2016, a deferred tax recovery was recorded. The recovery was largely due to unrealized risk management losses and the recognition of current year operating losses that will be claimed in a future period. 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. In addition, a one-time charge of approximately $158 million was recorded in 2015 from the revaluation of our deferred tax liability due to the increase in the Alberta corporate tax rate.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects higher U.S. tax rates, non-taxable unrealized foreign exchange (gains) losses, 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.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended September 30, 2016	2015	Nine Months Ended September 30, 2016	2015
Net Cash From (Used In)				
Operating Activities	**310**	542	**697**	1,152
Investing Activities	**(196)**	2,424	**(835)**	1,357
Net Cash Provided (Used) Before Financing Activities	**114**	2,966	**(138)**	2,509
Financing Activities	**(41)**	(134)	**(125)**	1,032
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(3)**	(21)	**8**	(23)
Increase (Decrease) in Cash and Cash Equivalents	**70**	2,811	**(255)**	3,518

($ millions)	September 30, 2016	December 31, 2015
Cash and Cash Equivalents	**3,850**	4,105
Committed and Undrawn Credit Facilities	**4,000**	4,000

Operating Activities

Cash from operating activities decreased for the three and nine months ended September 30, 2016 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 $4,283 million at September 30, 2016 compared with $4,337 million at December 31, 2015.

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

Investing Activities

Capital investment declined in the current quarter and on a year-to-date basis primarily due to spending reductions in response to the low commodity price environment. In 2015, cash from investing activities included proceeds of approximately $2.9 billion, net of tax, from the divestiture of our royalty interest and mineral fee title lands business.

Financing Activities

Cash used in financing activities decreased in the third quarter of 2016 as we paid dividends of $0.05 per share or $41 million (2015 – $0.16 per share or $133 million).

On a year-to-date basis, we paid dividends of $0.15 per share or $124 million (2015 – $0.6924 per share or $578 million, of which $396 million was paid in cash). In the nine months ended September 30, 2015, cash from financing activities included net proceeds of $1.4 billion from the issuance of common shares which was partially offset by a net repayment of short-term borrowings.

Our long-term debt at September 30, 2016 was $6,184 million (December 31, 2015 – $6,525 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 $341 million decrease in long-term debt is due to strengthening of the Canadian dollar relative to the U.S. dollar.

As at September 30, 2016, 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. 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:

($ millions)	Amount	Term
Cash and Cash Equivalents	**3,850**	**N/A**
Committed Credit Facility	**1,000**	**April 2019**
Committed Credit Facility	**3,000**	**November 2019**
U.S. Base Shelf Prospectus (1)	**US$5,000**	**March 2018**

(1) *Availability is subject to market conditions.*

Committed Credit Facility

We have a $4.0 billion committed credit facility, with $1.0 billion maturing on April 30, 2019 and $3.0 billion maturing on November 30, 2019. As at September 30, 2016, no amounts are drawn on our committed credit facilities.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

Base Shelf Prospectus

Cenovus filed a base shelf prospectus in 2016. The base shelf prospectus allows us to offer, from time to time, up to US$5.0 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere where permitted by law. The base shelf prospectus will expire in March 2018.

As at September 30, 2016, there were no issuances under the prospectus.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Debt to Capitalization and Debt to Adjusted EBITDA. We define our non-GAAP measure of Debt as short-term borrowings and the current and long-term portions of long-term debt. 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. Refer to Note 17 of the interim Consolidated Financial Statements for more details on the calculation of our financial metrics.

As at	**September 30, 2016**	December 31, 2015
Net Debt to Capitalization (1) (2)	**17%**	16%
Debt to Capitalization	**35%**	34%
Net Debt to Adjusted EBITDA (1)	**2.0x**	1.2x
Debt to Adjusted EBITDA	**5.3x**	3.1x

(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.

Over the long-term, we target a Debt to Capitalization ratio of between 30 percent to 40 percent and a Debt to Adjusted EBITDA of between 1.0 time to 2.0 times. At different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

Debt to Capitalization remained fairly consistent as the lower long-term debt balance, from the strengthening of the Canadian dollar relative to the U.S. dollar, was offset by the decrease in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of a decrease in Adjusted EBITDA, primarily due to a decline in Cash Flow from a reduction in commodity prices, partially offset by the lower long-term debt balance.

Share Capital and Stock-Based Compensation Plans

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Refer to Note 16 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at September 30, 2016	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**833,290**	**N/A**
Stock Options	**45,327**	**33,419**
Other Stock-Based Compensation Plans	**11,560**	**1,588**

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 and operating leases on buildings. 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.

In 2016, net transportation commitments declined by approximately $1.5 billion primarily due to a net decrease in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement, and should help align our future transportation requirements with our anticipated production growth. As at September 30, 2016, total transportation commitments were $26 billion.

As at September 30, 2016, there were outstanding letters of credit aggregating $275 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

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 sections of our 2015 annual MD&A and first and second quarters 2016 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, 2015, together with the updates provided in each of our first and second quarter 2016 MD&As.

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 2015 annual MD&A and AIF.

The following provides an update on our risks.

Federal Carbon Tax

In October 2016, the Canadian federal government announced a new national carbon pricing regime (the "Carbon Strategy") in response to the Paris Agreement that was ratified by Canada and other nations in October 2016. Under the Carbon Strategy, the federal government is proposing a benchmark carbon pricing program that includes, at a minimum, a price on carbon emissions of $10 per tonne in 2018, rising by $10 per tonne each year to $50 per tonne in 2022. The Carbon Strategy also proposes a federal backstop in the event that jurisdictions fail to meet the benchmark. Alberta has already established a carbon pricing system that was referenced in the federal announcement; therefore, in the short-term, the national price on carbon will likely have little additional impact.

Additional details of the Carbon Strategy are expected to be finalized in the coming months, and further legislation and regulation is expected from the provinces. At this time, Cenovus is unable to predict the impact of the Paris Agreement and the Carbon Strategy on its operations. It is possible that mandatory emissions reduction requirements may have a material adverse effect on Cenovus's financial condition, results of operations and cash flow. For more information on the risks to Cenovus related to the effects of climate change see our most recently filed AIF under "Risk Factors – Environment & Regulatory Risks – Climate Change", available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com.

Commodity Price Risk

Fluctuations in commodity prices and refined product prices impacts our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For 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 Notes 18 and 19 to the interim Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	Three Months Ended September 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(42)**	**(5)**	**(47)**	(195)	(141)	(336)
Natural Gas	**-**	**-**	**-**	(15)	15	-
Refining	**1**	**-**	**1**	(14)	(7)	(21)
Power [1]	**-**	**-**	**-**	4	6	10
Interest Rate	**-**	**12**	**12**	-	-	-
(Gain) Loss on Risk Management	**(41)**	**7**	**(34)**	(220)	(127)	(347)
Income Tax Expense (Recovery)	**11**	**(2)**	**9**	59	34	93
(Gain) Loss on Risk Management, After Tax	**(30)**	**5**	**(25)**	(161)	(93)	(254)

	Nine Months Ended September 30,					
	2016			2015		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(198)**	**359**	**161**	(355)	120	(235)
Natural Gas	**-**	**-**	**-**	(43)	41	(2)
Refining	**(4)**	**4**	**-**	(26)	5	(21)
Power [(1)]	**3**	**(14)**	**(11)**	7	3	10
Interest Rate	**-**	**91**	**91**	-	-	-
(Gain) Loss on Risk Management	**(199)**	**440**	**241**	(417)	169	(248)
Income Tax Expense (Recovery)	**52**	**(120)**	**(68)**	112	(48)	64
(Gain) Loss on Risk Management, After Tax	**(147)**	**320**	**173**	(305)	121	(184)

(1) *The power contracts were effectively terminated on March 7, 2016. Recent litigation between third parties has caused some uncertainty regarding termination of the contracts. Any related liability or asset to Cenovus is not determinable at this time.*

In the third quarter of 2016 and on a year-to-date basis, we incurred realized gains on crude oil risk management activities, consistent with our contract prices exceeding the average benchmark price. Unrealized gains were recorded on our crude oil financial instruments in the three months ended September 30, 2016, as a result of changes to market prices. On a year-to-date basis, we recorded unrealized losses primarily due to changes in market prices and the realization of settled positions.

Unrealized losses were recorded on our interest rate hedge positions due to decreases in benchmark interest rates.

Risks Associated With Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus of commodity price increases. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from 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, 2015.

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, 2016. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2015.

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.

Changes in Accounting Policies

There were no new or amended accounting standards or interpretations adopted during the nine months ended September 30, 2016.

Future Accounting Pronouncements

A description of additional accounting standards and interpretations that will be adopted in future periods can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended September 30, 2016 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.

OUTLOOK

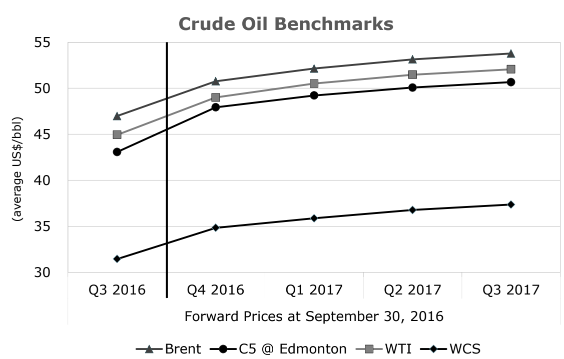
We anticipate ongoing price volatility for the foreseeable future and accordingly we continue to be prudent in how we allocate capital and manage the pace at which we choose to invest. Additional confidence in commodity prices, our ability to sustain cost reductions as well as fiscal and regulatory certainty are required before we will consider further expansion of existing projects or developing emerging opportunities. We will commit to project reactivation only if we believe it does not undermine the strength of our balance sheet.

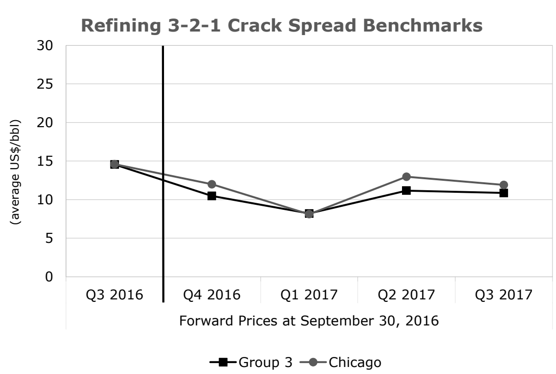
The following outlook commentary is focused on the next twelve months.

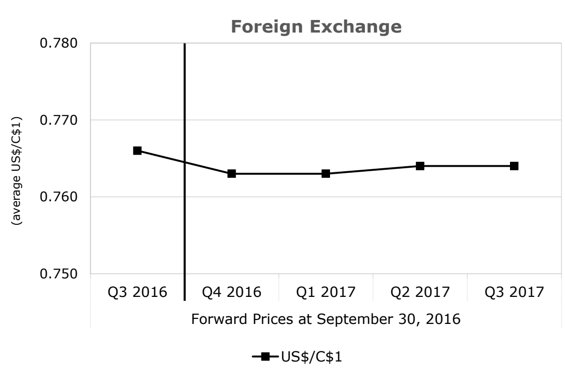
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, compliance of OPEC members with the plan to reduce production, the impact of supply disruptions and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility and a modest price improvement in the next twelve months.
- We anticipate the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and
- We expect that the WTI-WCS differential will widen due to increasing heavy oil production in Alberta.







U.S. refining crack spreads are expected to follow historical seasonal patterns over the next twelve months and will be impacted by the rebalancing of crude product markets. Overall, we expect 3-2-1 crack spreads to be influenced by the pace of inventory draws, which will be influenced by product demand strength.

Natural gas prices are anticipated to improve in the next twelve months due to lower supply growth and stronger demand growth, although price escalation is constrained by coal-to-gas substitution in the power sector.

We expect the Canadian dollar to continue to be tied with crude oil prices, tempered by differing interest rate expectations between Canada and the U.S. Overall, ignoring the change in oil price, a weaker Canadian dollar is expected to 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 a transportation cost component. 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 capable of processing Canadian heavy oil. From a value perspective, our refining business positions us 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 – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in 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.

Key Priorities for 2016

Maintain Financial Resilience

Maintaining our financial resilience, while maintaining safe operations, continues to be our top priority. At September 30, 2016, we had $3.9 billion of cash on hand and $4.0 billion of undrawn capacity under our committed credit facility. Our debt has a weighted average maturity of approximately 15 years, with no debt maturing until the fourth quarter of 2019. Although we have a strong balance sheet, we have undertaken additional measures in 2016 to remain financially resilient, including reductions in capital, operating and general and administrative costs.

Attack Cost Structures

We will continue to focus on reducing our cost structure. We have met our target of reducing our planned 2016 capital, operating, general and administrative spending by approximately $500 million, relative to our original 2016 budget released in December 2015. We will continue to ensure that, over the long term, we maintain an efficient and sustainable cost structure, and maximize the strengths of our functional business model.

Operational Excellence

We are focused on executing our work programs safely, responsibly and efficiently through standardized processes, procedures and controls. We use a manufacturing approach to optimize value, manage risk and improve performance. We are focused on reducing the environmental impact of our operations and engaging with people and communities who may be affected by our operations in a transparent, timely and respectful way.

ADVISORY

Oil and Gas Information

The estimates of reserves data and related information were prepared effective December 31, 2015 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, 2016 price forecast. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2015.

BOE – Natural gas volumes have been converted to a BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. 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", "estimate", "plan", "forecast" or "F", "future", "target", "position", "project", "capacity", "could", "should", "focus", "goal", "outlook", "proposed", "potential", "priority", "may", "schedule", "on track", "strategy", "forward", "opportunity" or similar expressions and includes suggestions of future outcomes, including statements about: our plans and related milestones and schedules; projected future value; projections for 2016 and future years; our future opportunities for oil development; 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 reserves; capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; our priorities for 2016; future impact of regulatory measures; forecast commodity prices and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices, derivative financial instruments, and the Carbon Strategy announced by the Canadian federal government; and the potential effectiveness of our risk management strategies. 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: forecast oil and natural gas prices and other assumptions inherent in Cenovus's 2016 guidance (as updated on October 27, 2016), available at cenovus.com; our projected capital investment levels, the flexibility of capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; 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; estimated abandonment and reclamation costs, including associated levies and regulations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2016 guidance (as updated on October 27, 2016), available at cenovus.com, assumes: Brent of US$44.98/bbl; WTI of US$43.29/bbl; WCS of US$29.48/bbl; NYMEX of US$2.47/MMBtu; AECO of $2.09/GJ; Chicago 3-2-1 crack spread of US$13.34/bbl; and an exchange rate of $0.76 US$/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; commodity prices, currency and interest rates; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; 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; our ability to finance growth and sustaining capital expenditures; 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 business; reliability of our assets, including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve acceptance in the market; risks associated with the fossil fuel industry reputation; 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; risks associated with climate change; the timing and the costs of well and pipeline construction; ability to secure adequate product transportation, including sufficient pipeline, crude-by-rail, marine or other alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; changes in our labour relationships; changes in the regulatory framework in any of the locations in which Cenovus operates, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental (including in relation to abandonment, reclamation and remediation costs, levies or liability recovery with respect thereto), 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, 2015, together with the updates under "Risk Management" in each of our first and second quarter 2016 MD&As, available on SEDAR at sedar.com, EDGAR at sec.gov and on our website at cenovus.com, and the updates under "Risk Management" in this MD&A.

ABBREVIATIONS

The following abbreviations 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
BOE	barrel of oil equivalent	GJ	gigajoule
BOE/d	barrel of oil equivalent per day	AECO	Alberta Energy Company
MBOE	thousand barrel of oil equivalent	NYMEX	New York Mercantile Exchange
MMBOE	million barrel of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	trademark of Cenovus Energy Inc.