MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED SEPTEMBER 30, 2017

WHERE TO FIND:

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", or "Cenovus", mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated November 1, 2017, should be read in conjunction with our September 30, 2017 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2016 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2016 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of November 1, 2017, 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. The information in this MD&A, as it relates to our operations for the three and nine months ended September 30, 2017, reflects the closing of the Acquisition (as defined in this MD&A) on May 17, 2017. 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 ("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, on 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 and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Debt, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Note 1 and Note 8 of our interim Consolidated Financial Statements. 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, if applicable, of each non-GAAP measure or additional subtotal is presented in the Financial Results, Operating Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On September 30, 2017, we had an enterprise value of approximately $27 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Western Canada. We also conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "liquids") production for the three months ended September 30, 2017 was 449,055 barrels per day, our average natural gas production was 851 MMcf per day, and our total reported production was 590,851 BOE per day. The refining operations processed an average of 462,000 gross barrels per day of crude oil feedstock into an average of 490,000 gross barrels per day of refined products.

Our Strategy

On May 17, 2017, we closed an acquisition from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") where we acquired their 50 percent interest in FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional assets in Alberta and British Columbia ("the Acquisition"). In order to finance the Acquisition, we incurred additional debt. We are focused on deleveraging our balance sheet through the sale of our legacy Conventional crude oil and natural gas assets and generating increased Free Funds Flow.

We updated our strategy in the second quarter of 2017 to reflect the closing of the Acquisition and our increased focus on Free Funds Flow. Our strategy is to increase cash flows through disciplined production growth from our vast portfolio of oil sands and Deep Basin natural gas and liquids assets in Western Canada. We are focused on increasing our current share price and maximizing shareholder value through cost leadership and realizing the best margins for our products to help us maintain financial resilience and deliver sustainable dividend growth. We plan to achieve our strategy by drawing on the expertise of our people and leveraging our strategic differentiators: premium asset quality, executional excellence, value-added integration, focused innovation and trusted reputation.

We measure our performance through a balanced scorecard that reflects our financial, operational, safety, environmental and organizational health goals.

Our Key Strategic Differentiators

Premium Asset Quality

Cenovus has a deep portfolio of premium-quality oil sands, conventional oil, and natural gas assets that we believe provide us with significant cost and environmental performance advantages. Our in-situ oil sands projects and Deep Basin assets in Western Canada offer long- and short-cycle opportunities that provide the capital investment flexibility to position us to deliver value growth at various points of the price cycle. In addition to our exploration and production assets, we have complementary interests in refineries and product transportation infrastructure.

Executional Excellence

Our team is committed to delivering on our business plan in a safe, disciplined and responsible manner and continuously improving our performance to help manage risk and optimize returns. We use a manufacturing approach to support consistent performance and enhance reliability. This involves applying standardized and repeatable designs and processes to the construction and operation of our facilities to reduce costs and improve efficiencies at all project stages. We strive to execute our work in an agile manner with a focus on using our resources effectively.

Value-Added Integration

Our integrated business approach helps provide stability to our cash flows and maximize value for the oil and natural gas we produce. Having ownership in oil refineries positions us to capture the full value chain from production to high-quality end products like transportation fuels. In addition, our pipeline commitments, marine capability, crude-by-rail loading facility and product marketing activities position us to obtain global pricing for our oil. As a consumer of natural gas at our oil sands facilities and refineries, our natural gas production acts as an economic hedge to help manage price volatility. In addition, our cogeneration plants efficiently provide power for our oil sands facilities with the added value of excess electricity being sold to the grid.

Focused Innovation

We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, aggressively reduce costs, improve margins and lower emissions. We expect innovation at Cenovus to mean significant improvements and game-changing developments that are implemented to generate value. We embrace the "fail fast" mentality as essential to encouraging behaviours that can transform how we operate. The application of digital innovation across our business is expected to be a key contributor to our competitive advantage. We aim to complement our internal technology development efforts with external collaboration that brings together smart people with diverse ideas that leverage our technology spend.

Trusted Reputation

We are a responsible, progressive company that is committed to providing a safe and healthy workplace, building strong external relationships, minimizing our environmental footprint and being a part of a zero-emissions future. Our actions are intended to support our trusted reputation and enable us to attract and retain top-quality staff and to engage with and be respected by our stakeholders: investors, the communities in which we operate, environmental groups, governments, Aboriginal people, media, project partners and the general public.

Our Operations

Oil Sands

Our oil sands assets include steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta, including Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects, located in the Athabasca region of northeastern Alberta, are 100 percent owned by Cenovus following the Acquisition. Our 100 percent-owned emerging project at Telephone Lake is located within the Borealis region of northeastern Alberta. 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.

	Nine Months Ended September 30, 2017	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Margin	**1,612**	**3**
Capital Investment	**654**	**6**
Operating Margin Net of Related Capital Investment	**958**	**(3)**

Deep Basin

The Deep Basin includes approximately three million net acres of land rich in natural gas, condensate and other NGLs, and light and medium oil. The assets are located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas and include interests in numerous natural gas processing facilities (collectively, the "Deep Basin Assets"). The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development and provide an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations. The Deep Basin Assets were acquired on May 17, 2017.

($ millions)	**May 17 – September 30, 2017**
Operating Margin	**119**
Capital Investment	**77**
Operating Margin Net of Related Capital Investment	**42**

Conventional

Our Conventional segment has been classified as a discontinued operation. We are currently marketing for sale or have sales agreements in place for the remaining assets within our Conventional segment. In the third quarter, we sold our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project, for gross cash proceeds of $975 million. We also announced the divestiture of our Suffield crude oil and natural gas assets for gross cash proceeds of $512 million. The sale is expected to close in the fourth quarter of 2017, subject to customary closing conditions.

On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of $1.3 billion. The sale of the Palliser assets is expected to close in the fourth quarter of 2017, subject to customary closing conditions.

Crude oil production from our Conventional business segment generates dependable near-term cash flows while the 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.

($ millions)	Nine Months Ended September 30, 2017	
	Liquids	**Natural Gas**
Operating Margin	**310**	**109**
Capital Investment	**173**	**7**
Operating Margin Net of Related Capital Investment	**137**	**102**

Refining and Marketing

Our operations include two refineries located in Illinois and Texas that are jointly owned with (50 percent interest) and operated by Phillips 66, an unrelated U.S. public company. The gross crude oil capacity at the Wood River and Borger refineries (the "Refineries") is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. This includes processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The 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, 2017**
Operating Margin	**284**
Capital Investment	**124**
Operating Margin Net of Related Capital Investment	**160**

FINANCING THE ACQUISITION

On May 17, 2017, we closed the Acquisition which provided us with control over our oil sands operations, doubled our oil sands production, and almost doubled our proved bitumen reserves. In addition, the Deep Basin Assets provide a second core operating area with more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia. The Deep Basin Assets are expected to provide complementary short-cycle development opportunities with high-return potential.

The safe and efficient integration of the Deep Basin Assets is on track and continues to be a top priority for Cenovus. We are committed to ensuring responsible operations as we establish ourselves as a new operator in the Deep Basin area.

To finance the Acquisition, we:

- Completed an offering for US$2.9 billion of senior unsecured notes;
- Borrowed $3.6 billion under a committed asset sale bridge credit facility ("Bridge Facility");
- Completed a Bought-Deal Common Share Offering for 187.5 million common shares, raising gross proceeds of $3.0 billion;
- Issued 208 million common shares as part of the consideration paid to ConocoPhillips; and
- Funded the remainder of the purchase price with cash on hand and a draw on our existing committed credit facility.

The financing, which increased the leverage on our balance sheet, was executed according to plan and supported by three investment grade credit ratings. The increase in leverage is expected to be temporary as we are selling our legacy Conventional crude oil and natural gas assets in order to deleverage our balance sheet. We have completed the first of a series of anticipated divestitures, namely our Pelican Lake assets and the adjacent Grand Rapids project, for gross cash proceeds of $975 million. Net cash proceeds from the sale have been applied against the $3.6 billion committed Bridge Facility.

On September 25, 2017, we announced the sale of our Suffield crude oil and natural gas operations in southern Alberta for gross cash proceeds of $512 million, plus a deferred purchase price adjustment ("DPPA"). The sale includes our crude oil and natural gas assets located on the Canadian Forces Base Suffield and the adjacent Alderson property (collectively, the "Suffield Divestiture"). The DPPA is a two-year agreement that begins on January 1, 2018, with maximum combined purchase price adjustments of $36 million if average crude oil and natural gas prices rise over the next two years. We are entitled to receive cash for each month in which the average daily price of WTI is above US$55 per barrel or the price of Henry Hub natural gas is above US$3.50 per MMBtu. The Suffield Divestiture is expected to close in the fourth quarter, subject to customary closing conditions.

On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of $1.3 billion. The sale includes our crude oil and natural gas assets in the areas near Drumheller, Brooks and Langevin (collectively, the "Palliser Divestiture"). The sale of the Palliser assets is expected to close in the fourth quarter of 2017, subject to closing conditions. The divestiture process for our remaining legacy Conventional assets, notably our CO_2 enhanced oil recovery project at Weyburn, in southern Saskatchewan, is proceeding well.

Additional information on the Acquisition is available in our June 30, 2017 MD&A and our news release dated March 29, 2017 available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com; in our material change report dated April 5, 2017 and in our Business Acquisition Report dated July 19, 2017, both available on SEDAR and EDGAR.

QUARTERLY HIGHLIGHTS

We have completed key steps in the plan to deleverage our balance sheet with the announcement of three divestitures, closing one of them. Gross proceeds from these divestitures will total approximately $2.8 billion.

We generated Free Funds Flow of $544 million in the quarter, a significant increase from $214 million in the third quarter of 2016, primarily due to the Acquisition.

Production increased significantly in the quarter to 590,851 BOE per day in 2017 (2016 – 273,405 BOE per day) primarily related to the Acquisition. Incremental production from the Acquisition was 296,549 BOE per day for the three months ended September 30, 2017.

Crude oil prices continued to be volatile in the quarter. WTI ranged from a high of US$52.22 per barrel to a low of US$44.23 per barrel and averaged seven percent higher compared with 2016. In addition, AECO was very volatile, ranging from a high of $2.71 per Mcf to a low of $1.24 Mcf and averaging seven percent lower than the third quarter of 2016. Our average sales price rose 12 percent from 2016, contributing to a companywide Netback of $18.40 per BOE in the third quarter, before realized hedging. We continue to focus on cost leadership and capital discipline to help maintain financial resilience, while delivering safe and reliable operations.

In the third quarter, we:

- More than doubled our total liquids production compared with the third quarter of 2016, primarily due to incremental production volumes from the Acquisition and our oil sands expansion phases;
- Generated combined upstream revenues, including the Conventional segment, of $2,629 million compared with $1,084 million in 2016, primarily related to a rise in sales volumes and higher liquids sales prices;
- Reported upstream operating costs, including the Conventional segment, of $476 million, an increase of $246 million compared with the third quarter of 2016 primarily due to the Acquisition;
- Achieved Cash From Operating Activities and Adjusted Funds Flow of $592 million and $982 million, respectively, increasing significantly from the third quarter of 2016;
- Recorded Net Earnings From Continuing Operations of $288 million (2016 – Net Loss From Continuing Operations of $55 million);
- Invested $438 million in capital which allowed us to generate Free Funds Flow of $544 million in the quarter;
- Sold our Pelican Lake assets and the adjacent Grand Rapids project on September 29, 2017 for gross cash proceeds of $975 million and repaid the first tranche and a portion of the second tranche of our committed Bridge Facility; and
- Announced the Suffield Divestiture. The sale is expected to close in the fourth quarter, subject to customary closing conditions, generating gross cash proceeds of $512 million, plus a DPPA.

In October, we announced the Palliser Divestiture. The sale is expected to close in the fourth quarter, subject to customary closing conditions, generating gross cash proceeds of $1.3 billion.

OPERATING RESULTS

Our upstream assets continued to perform well in the three and nine months ended September 30, 2017. Total production increased primarily due to the Acquisition.

Production Volumes

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**Percent Change**	2016	**2017**	**Percent Change**	2016
Liquids (barrels per day)						
Oil Sands						
Foster Creek	**154,363**	**109%**	73,798	**114,632**	**73%**	66,435
Christina Lake	**208,131**	**161%**	79,793	**154,634**	**97%**	78,321
	362,494	**136%**	153,591	**269,266**	**86%**	144,756
Deep Basin						
Light and Medium Oil	**6,494**	**-%**	-	**3,208**	**-%**	-
NGLs	**26,370**	**-%**	-	**13,498**	**-%**	-
	32,864	**-%**	-	**16,706**	**-%**	-
Conventional (Discontinued Operations)						
Heavy Oil	**25,549**	**(9)%**	28,096	**26,466**	**(10)%**	29,276
Light and Medium Oil	**26,947**	**6%**	25,311	**26,430**	**1%**	26,200
NGLs	**1,201**	**12%**	1,074	**1,128**	**10%**	1,027
	53,697	**(1)%**	54,481	**54,024**	**(4)%**	56,503
Total Liquids Production (barrels per day)	**449,055**	**116%**	208,072	**339,996**	**69%**	201,259
Natural Gas (MMcf per day)						
Oil Sands	**6**	**(67)%**	18	**11**	**(35)%**	17
Deep Basin	**495**	**-%**	-	**251**	**-%**	-
Conventional (Discontinued Operations)	**350**	**(6)%**	374	**351**	**(8)%**	382
Total Natural Gas Production (MMcf per day)	**851**	**117%**	392	**613**	**54%**	399
Total Production (BOE per day)	**590,851**	**116%**	273,405	**442,143**	**65%**	267,759

The increase in production at Foster Creek and Christina Lake from May 17, 2017, the closing date of the Acquisition, until September 30, 2017 was 76,127 barrels per day and 104,985 barrels per day, respectively.

Production at Foster Creek increased in the third quarter and on a year-to-date basis compared with 2016 due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues in the third quarter. On a year-to-date basis, production at Foster Creek was also impacted by approximately 3,690 barrels per day due to a planned turnaround completed in the second quarter of 2017. Production at Christina Lake increased in the three and nine months ended September 30, 2017 compared to the same periods in 2016 due to the Acquisition and incremental production volumes from the phase F expansion.

Total liquids production in the Deep Basin for the 137 day period following the Acquisition averaged 33,290 barrels per day.

Our Conventional liquids production decreased in the third quarter and on a year-to-date basis compared with 2016 primarily due to expected natural declines, partially offset by an increase in production associated with the tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

In the third quarter and on a year-to-date basis, our natural gas production rose compared with 2016 due to the Acquisition, partially offset by expected natural declines in our Conventional segment. Natural gas production from the Deep Basin for the 137 days of operations in 2017 was 500 MMcf per day.

Netbacks

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis. Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses, and production and mineral taxes divided by sales volumes. Netbacks do not reflect the non-cash write-downs of product inventory until the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($/BOE)	**2017**	2016	**2017**	2016
Sales Price	**33.71**	29.98	**34.89**	24.37
Royalties	**2.08**	1.55	**2.37**	1.29
Transportation and Blending	**4.56**	4.51	**4.56**	4.69
Operating Expenses	**8.59**	8.92	**9.18**	9.32
Production and Mineral Taxes	**0.08**	0.15	**0.12**	0.12
Netback Excluding Realized Risk Management [(1)]	**18.40**	14.85	**18.66**	8.95
Realized Risk Management Gain (Loss)	**(0.24)**	1.63	**(0.77)**	3.05
Netback Including Realized Risk Management [(1)]	**18.16**	16.48	**17.89**	12.00

(1) Includes results from our Conventional segment, which has been classified as a discontinued operation.

The rise in our average Netback was primarily due to higher liquids sales prices, partially offset by a rise in royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. In the third quarter of 2017, our average Netback rose despite a decline in natural gas prices. On a year-to-date basis, the strengthening of the Canadian dollar compared with 2016 had a negative impact on our sales price of approximately $0.40 per BOE.

Refining

In the third quarter, refined product output declined compared with 2016 primarily due to unplanned maintenance at both Refineries in 2017. In addition, lower heavy crude oil volumes were processed due to optimization of the total crude input slate to address narrowing heavy crude oil differentials.

On a year-to-date basis, crude oil runs and refined product output decreased due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2017 compared with 2016, in addition to unplanned maintenance at both Refineries in 2017.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	**Percent Change**	2016	**2017**	**Percent Change**	2016
Crude Oil Runs [(1)] (Mbbls/d)	**462**	**-%**	463	**439**	**(3)%**	452
Heavy Crude Oil [(1)]	**213**	**(12)%**	241	**205**	**(14)%**	237
Refined Product [(1)] (Mbbls/d)	**490**	**(1)%**	494	**467**	**(3)%**	479
Crude Utilization [(1)] (percent)	**100**	**(1)%**	101	**95**	**(3)%**	98

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

Operating Margin from Refining and Marketing in the three and nine months ended September 30, 2017 was $211 million and $284 million, respectively (2016 – $68 million and $238 million, respectively). The increases were primarily due to higher average market crack spreads, partially offset by narrowing heavy crude oil differentials.

Further information on the changes in our production volumes, items included in our 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 interim Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [1]

(US$/bbl, unless otherwise indicated)	Nine Months Ended September 30, 2017	2016	Percent Change	Q3 2017	Q2 2017	Q3 2016
Crude Oil Prices						
Brent						
Average	**52.59**	43.01	**22%**	**52.18**	50.92	46.98
End of Period	**57.54**	49.06	**17%**	**57.54**	47.92	49.06
WTI						
Average	**49.47**	41.33	**20%**	**48.21**	48.29	44.94
End of Period	**51.67**	48.24	**7%**	**51.67**	46.04	48.24
Average Differential Brent-WTI	**3.12**	1.68	**86%**	**3.97**	2.63	2.04
WCS						
Average	**37.59**	27.65	**36%**	**38.27**	37.16	31.44
Average (C$/bbl)	**49.07**	36.53	**34%**	**47.96**	49.95	41.04
End of Period	**40.71**	34.97	**16%**	**40.71**	36.36	34.97
Average Differential WTI-WCS	**11.88**	13.68	**(13)%**	**9.94**	11.13	13.50
Condensate (C5 @ Edmonton)						
Average [2]	**49.44**	40.51	**22%**	**47.61**	48.44	43.07
Average Differential WTI-Condensate (Premium)/Discount	**0.03**	0.82	**(96)%**	**0.60**	(0.15)	1.87
Average Differential WCS-Condensate (Premium)/Discount	**(11.85)**	(12.86)	**(8)%**	**(9.34)**	(11.28)	(11.63)
Mixed Sweet Blend (“MSW” @ Edmonton)						
Average [3]	**46.57**	38.09	**22%**	**45.32**	46.03	41.99
End of Period	**49.76**	45.92	**8%**	**49.76**	43.66	45.92
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline (“RUL”)	**64.48**	55.17	**17%**	**66.87**	63.44	59.27
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**65.26**	54.60	**20%**	**69.73**	62.18	59.86
Refining Margin: Average 3-2-1 Crack Spreads [4]						
Chicago	**15.33**	13.77	**11%**	**19.66**	14.78	14.58
Average Natural Gas Prices						
AECO (C$/Mcf)	**2.58**	1.85	**39%**	**2.04**	2.77	2.20
NYMEX (US$/Mcf)	**3.17**	2.29	**38%**	**3.00**	3.18	2.81
Basis Differential NYMEX-AECO (US$/Mcf)	**1.21**	0.89	**36%**	**1.39**	1.13	1.13
Foreign Exchange Rate (US$ per C$1)						
Average	**0.766**	0.757	**1%**	**0.798**	0.744	0.766

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

(2) *The average Canadian dollar condensate benchmark price for the third quarter of 2017 was $59.66 per barrel (2016 – $56.23 per barrel) and for the nine months ended September 30, 2017 was $64.54 per barrel (2016 – $53.51 per barrel).*

(3) *The average Canadian dollar MSW benchmark price for the third quarter of 2017 was $56.79 per barrel (2016 – $54.82 per barrel) and for the nine months ended September 30, 2017 was $60.80 per barrel (2016 – $50.32 per barrel).*

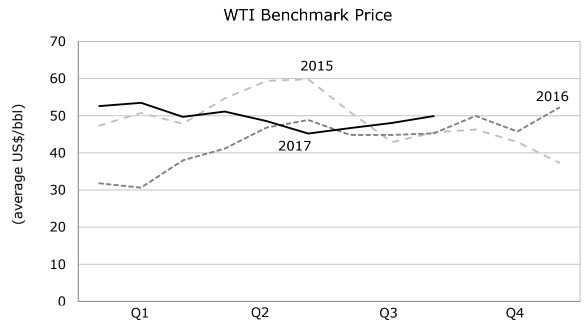
(4) *The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.*

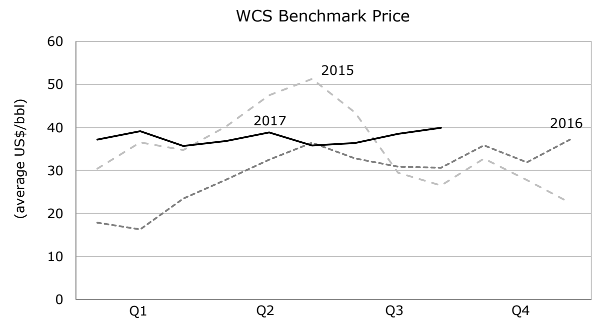
Crude Oil Benchmarks

The average Brent, WTI and Western Canadian Select (“WCS”) benchmark prices improved in the nine months ended September 30, 2017 compared with 2016. Compliance with the production cuts outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries (“OPEC”) led to wide-spread market expectations of an accelerated return to normal inventory levels. However, without supporting supply and demand drivers, prices continued to be volatile as growing supply from the U.S., unstable supply from Libya and Nigeria, severe weather related incidents, and strong global demand resulted in varying expectations on the pace of crude oil and refined product inventory draws.

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. WTI benchmark prices weakened relative to Brent compared with the third quarter of 2016 and on a year-to-date basis due to growing U.S. crude oil supply. In the third quarter of 2017, severe weather related incidents and strong global demand resulted in declines to crude oil and refined product inventory levels.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in the third quarter and on a year-to-date basis compared with 2016. WCS strengthened relative to WTI due to a decrease in supply of blended heavy oil as a result of temporary upgrading outages related to a processing facility fire in Alberta. In addition, WCS increased due to higher demand as a result of OPEC’s compliance with production cuts and lower supply from Mexico and Colombia.





Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios range from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost attributed to transporting the condensate to Edmonton.

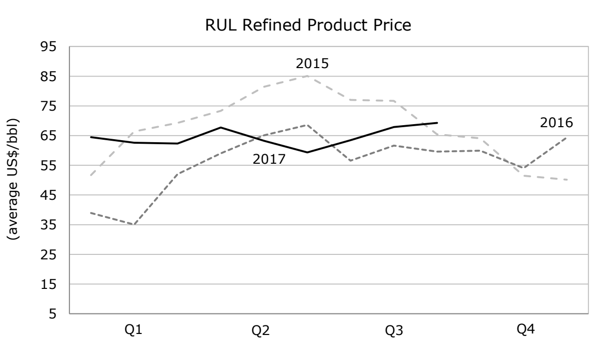
The average WTI-Condensate differential narrowed in the third quarter and on a year-to-date basis compared to 2016 as a result of lower spare capacity on pipelines which increased the cost of transporting condensate to Edmonton.

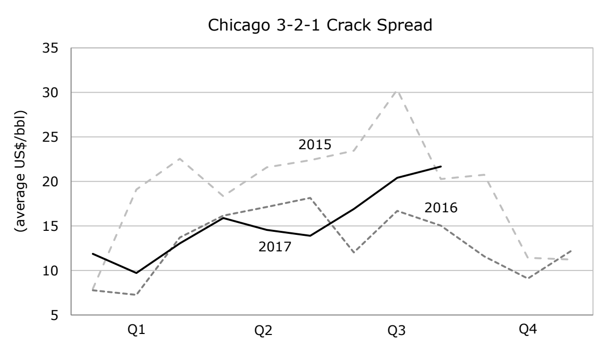
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price declined in the third quarter of 2017 compared with the second quarter as a result of synthetic crude oil supply returning to the market after temporary upgrading outages related to a processing facility fire in the second quarter of 2017.

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 refined product prices increased in the third quarter of 2017 and on a year-to-date basis primarily due to strong refined product demand and severe weather related events that impacted the refined product output of U.S. Gulf Coast refineries. Average Chicago 3-2-1 crack spreads rose in the three and nine months ended September 30, 2017 compared with 2016 due to the wider Brent-WTI differential, a decline in refined product supplied from the U.S. Gulf Coast, and strong refined product demand. Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, 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 AECO prices in the third quarter decreased compared with 2016 primarily due to higher natural gas supply in Alberta resulting from extensive pipeline and compressor station maintenance decreasing deliverability to storage facilities and reducing export capability. Average NYMEX natural gas prices increased in 2017 compared with the third quarter of 2016 due to lower levels of natural gas in storage.

On a year-to-date basis, average AECO and NYMEX natural gas prices rose significantly compared with 2016. Natural gas prices strengthened as North American inventory levels declined due to lower production and stronger demand. Production decreased as a result of reduced drilling programs while demand increased from additional capacity to export North American natural gas to foreign markets, partially offset by mild weather and less natural gas used for domestic electricity generation. In addition, natural gas prices in 2016 were negatively impacted by an exceptionally warm winter that resulted in poor heating demand and record-high seasonal North American natural gas storage levels.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, our reported results are higher. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In the third quarter and on a year-to-date basis, the Canadian dollar strengthened relative to the U.S. dollar due to strengthening of the Canadian economy, increases in the Bank of Canada benchmark lending rate and higher commodity prices. The strengthening of the Canadian dollar in the nine months ended September 30, 2017, compared with 2016, had a negative impact of approximately $155 million on our revenues, including our Conventional segment. As at September 30, 2017, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2016, which resulted in $715 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

In the three and nine months ended September 30, 2017, the Acquisition and improvements in commodity prices were the primary drivers of our 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,**		**2017**			2016				2015	
	2017	2016	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Revenues (1)	**11,964**	7,682	**4,386**	4,037	3,541	3,324	2,945	2,746	1,991	2,601	2,905
Operating Margin (2)											
Total Operating Margin	**2,444**	1,172	**1,216**	778	450	595	487	541	144	357	602
From Continuing Operations	**2,023**	781	**1,099**	619	305	442	335	424	22	153	360
Cash From Operating Activities											
Total Cash From Operating Activities	**2,159**	697	**592**	1,239	328	164	310	205	182	322	542
From Continuing Operations	**1,778**	404	**481**	1,102	195	22	189	121	94	123	366
Adjusted Funds Flow (3)											
Total Adjusted Funds Flow	**2,097**	888	**982**	792	323	535	422	440	26	275	444
From Continuing Operations	**1,700**	583	**867**	650	183	382	296	352	(65)	71	266
Operating Earnings (Loss) (3)											
Total Operating Earnings (Loss)	**699**	(698)	**340**	398	(39)	321	(236)	(39)	(423)	(438)	(28)
Per Share – Diluted ($)	**0.66**	(0.84)	**0.28**	0.36	(0.05)	0.39	(0.28)	(0.05)	(0.51)	(0.53)	(0.03)
From Continuing Operations	**558**	(312)	**253**	344	(39)	21	(40)	(3)	(269)	(245)	(23)
Per Share – Diluted ($)	**0.53**	(0.37)	**0.21**	0.31	(0.05)	0.03	(0.05)	-	(0.32)	(0.29)	(0.03)
Net Earnings (Loss) From Continuing Operations	**3,080**	(250)	**288**	2,581	211	(209)	(55)	(231)	36	(448)	1,806
Per Share – Basic and Diluted ($)	**2.91**	(0.30)	**0.23**	2.32	0.25	(0.25)	(0.07)	(0.28)	0.04	(0.54)	2.17
Net Earnings (Loss)	**2,782**	(636)	**(69)**	2,640	211	91	(251)	(267)	(118)	(641)	1,801
Per Share – Basic and Diluted ($)	**2.62**	(0.76)	**(0.06)**	2.37	0.25	0.11	(0.30)	(0.32)	(0.14)	(0.77)	2.16
Capital Investment (4)	**1,078**	767	**438**	327	313	259	208	236	323	428	400
Free Funds Flow (3)	**1,019**	121	**544**	465	10	276	214	204	(297)	(153)	44
Dividends											
Cash Dividends	**164**	124	**62**	61	41	42	41	42	41	132	133
Per Share ($)	**0.15**	0.15	**0.05**	0.05	0.05	0.05	0.05	0.05	0.05	0.16	0.16

(1) *Excludes revenues from discontinued operations. For the three and nine months ended September 30, 2017, revenues related to discontinued operations were $286 million and $946 million, respectively (2016 – $295 million and $810 million, respectively).*
(2) *Additional subtotal found in Note 1 and Note 8 of the interim Consolidated Financial Statements and defined in this MD&A.*
(3) *Non-GAAP measure defined in this MD&A.*
(4) *Includes expenditures on Property, Plant and Equipment ("PP&E"), Exploration and Evaluation ("E&E") assets, and assets held for sale.*

Revenues

($ millions)	Three Months Ended	Nine Months Ended
Revenues for the Periods Ended September 30, 2016	**2,945**	**7,682**
Increase (Decrease) due to:		
Oil Sands	**1,367**	**2,856**
Deep Basin	**187**	**303**
Refining and Marketing	**(84)**	**1,200**
Corporate and Eliminations	**(29)**	**(77)**
Revenues for the Periods Ended September 30, 2017	**4,386**	**11,964**

Combined upstream revenues, excluding revenues from our Conventional segment, rose significantly in the third quarter and on a year-to-date basis, compared with 2016. The increase was primarily related to a rise in sales volumes due to the Acquisition and the incremental volumes from the oil sands expansion phases and higher crude oil commodity prices. These increases were partially offset by higher royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. Conventional revenues have been reported in net earnings from discontinued operations and are discussed below.

Revenues from our Refining and Marketing segment in the third quarter of 2017 decreased by four percent. Refining revenues rose compared with 2016 primarily due to an increase in refined product pricing, partially offset by a decline in refined product output and the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group decreased significantly in the three months ended September 30, 2017 compared with 2016 primarily due to a decrease in purchased products and lower crude oil and natural gas sales prices.

On a year-to-date basis, Refining and Marketing revenues increased 20 percent. Refining revenues rose due to higher refined product pricing, consistent with the rise in average Chicago refined product benchmark prices, partially offset by decreased refined product output and the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group increased in the nine months ended September 30, 2017 compared with 2016 due to higher crude oil and natural gas sales prices and an increase in purchased crude oil and condensate volumes, partially offset by a decline in natural gas volumes.

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

In the second quarter of 2017, our Conventional segment was classified as a discontinued operation as we intend to divest all of our legacy Conventional assets. For the three and nine months ended September 30, 2017, Conventional revenues were $286 million and $946 million, respectively (2016 – $295 million and $810 million, respectively). Revenues declined slightly in the third quarter of 2017 due to lower natural gas prices, a rise in royalties, and the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by higher crude oil prices. On a year-to-date basis, the increase in revenues compared with 2016 was primarily due to higher commodity prices, partially offset by a rise in royalties and a decline in sales volumes.

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

Operating Margin

Operating Margin is an additional subtotal found in Note 1 and Note 8 of the interim Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, 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 Margin.

Total Operating Margin

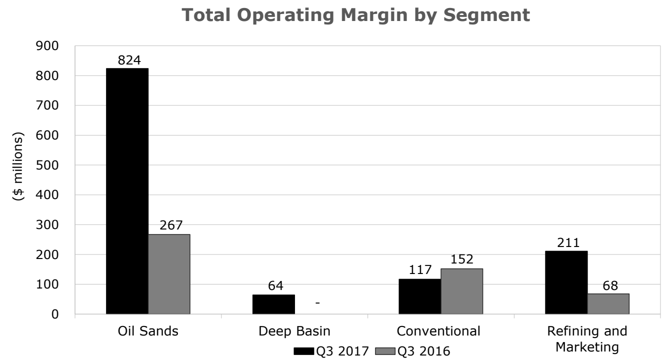
	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Revenues	**4,790**	3,329	**13,232**	8,737
(Add) Deduct:				
Purchased Product	**1,782**	2,004	**6,295**	5,144
Transportation and Blending	**1,132**	473	**2,692**	1,364
Operating Expenses	**644**	402	**1,692**	1,247
Production and Mineral Taxes	**4**	4	**14**	9
Realized (Gain) Loss on Risk Management Activities	**12**	(41)	**95**	(199)
Total Operating Margin [(1)]	**1,216**	487	**2,444**	1,172

(1) *Includes results from our Conventional segment, which has been classified as a discontinued operation.*

Three Months Ended September 30, 2017 Compared With September 30, 2016

Total Operating Margin more than doubled in the third quarter of 2017 compared with 2016 primarily due to:

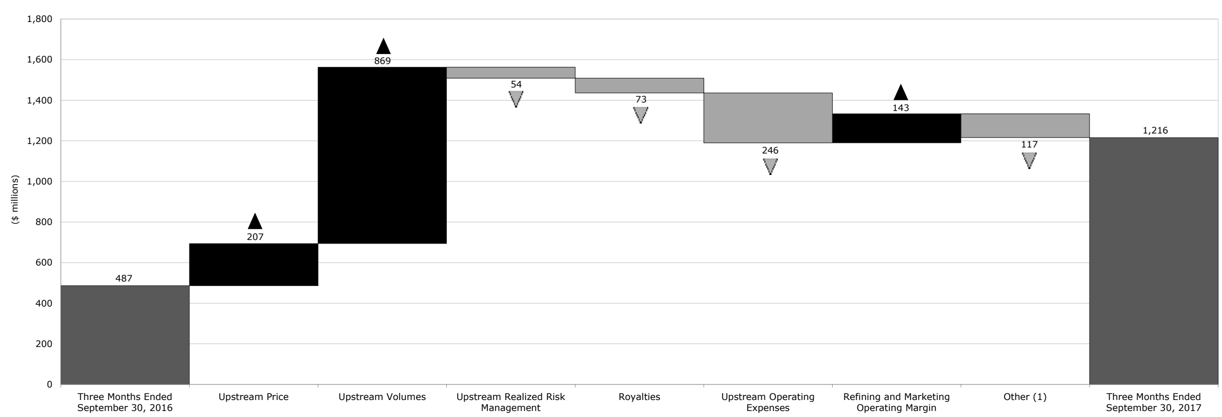
- A significant increase in our liquids and natural gas sales volumes primarily related to the Acquisition and our oil sands expansion phases;
- A rise in our average liquids sales price due to improved benchmark prices; and
- A higher Operating Margin from Refining and Marketing primarily due to an increase in average market crack spreads and a rise in margins on the sale of our secondary products, partially offset by narrowing heavy crude oil differentials, and a strengthening of the Canadian dollar relative to the U.S. dollar.



These increases in Operating Margin were partially offset by:

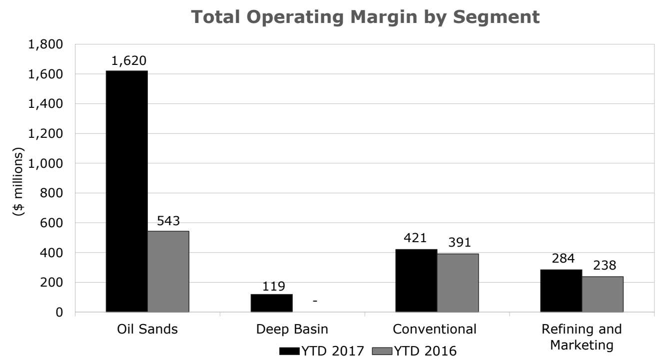
- A rise in transportation and blending expenses primarily due to higher blending costs related to an increase in condensate volumes required for blending our increased oil sands production along with higher condensate prices;
- An increase in operating expenses primarily due to the Acquisition;
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), an increase in sales volumes due to the Acquisition, and a rise in our liquids sales price;
- Realized risk management losses of $12 million, associated with our upstream assets, compared with gains of $42 million in the third quarter of 2016; and
- A decline in our natural gas sales price from 2016.

Total Operating Margin Variance



(1) *Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Nine Months Ended September 30, 2017 Compared With September 30, 2016



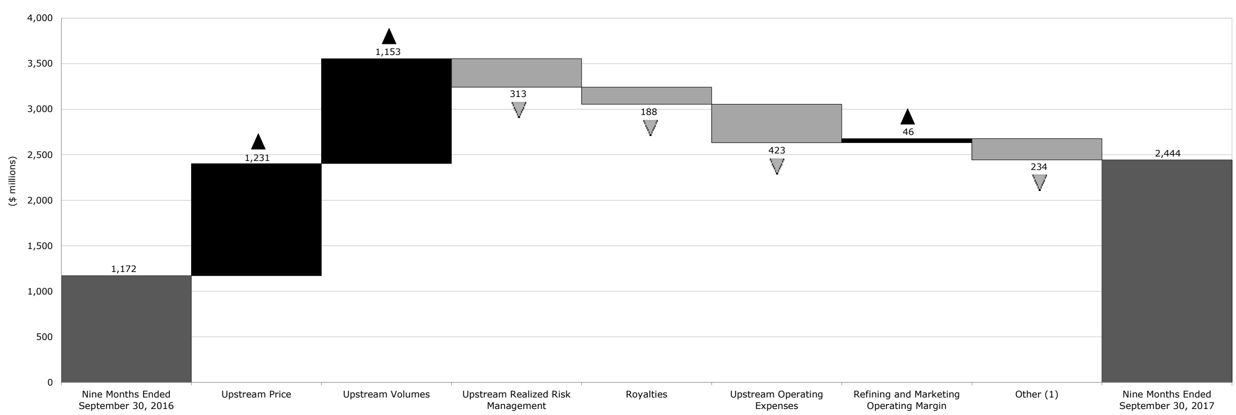
Operating Margin more than doubled in the nine months ended September 30, 2017 compared with 2016 primarily due to:

- A rise in our average liquids and natural gas sales prices due to improved benchmark prices;
- An increase in our liquids sales volumes primarily related to the Acquisition and our 2016 oil sand expansion phases, and a rise in our natural gas sales volumes primarily due to the acquired Deep Basin Assets; and
- A higher Operating Margin from Refining and Marketing due to an increase in average market crack spreads, a rise in margins on the sale of our secondary products, and lower realized risk management losses, partially offset by narrowing heavy crude oil differentials, lower crude utilization rates, and an increase in operating costs.

These increases to Operating Margin were partially offset by:

- A rise in transportation and blending expenses primarily due to higher blending costs, related to an increase in condensate volumes required for blending our increased oil sands production along with higher condensate prices;
- An increase in operating expenses primarily due to the Acquisition and higher fuel costs related to the increase in natural gas pricing;
- Realized risk management losses of $91 million, associated with our upstream assets, compared with gains of $222 million in 2016; and
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), a rise in our liquids sales price, and an increase in sales volumes due to the Acquisition.

Total Operating Margin Variance



(1) *Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

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

Operating Margin From Continuing Operations

Operating Margin From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Revenues	**4,504**	3,034	**12,286**	7,927
(Add) Deduct:				
Purchased Product	**1,782**	2,004	**6,295**	5,144
Transportation and Blending	**1,088**	429	**2,543**	1,228
Operating Expenses	**526**	300	**1,349**	916
Realized (Gain) Loss on Risk Management Activities	**9**	(34)	**76**	(142)
Operating Margin From Continuing Operations	**1,099**	335	**2,023**	781

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds 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. Adjusted Funds Flow is defined as Cash From Operating Activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

Total Cash From Operating Activities and Adjusted Funds Flow

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Cash From Operating Activities [(1)]	**592**	310	**2,159**	697
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(19)**	(13)	**(75)**	(59)
Net Change in Non-Cash Working Capital	**(371)**	(99)	**137**	(132)
Adjusted Funds Flow [(1)]	**982**	422	**2,097**	888

(1) Includes results from our Conventional segment, which has been classified as a discontinued operation.

In the third quarter of 2017, Cash From Operating Activities and Adjusted Funds Flow increased primarily as a result of a higher Operating Margin, as discussed above, partially offset by realized foreign exchange losses on working capital compared with realized foreign exchange gains in 2016, a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition, and higher general and administrative expenses.

On a year-to-date basis, Cash From Operating Activities and Adjusted Funds Flow increased compared with 2016 due to a higher Operating Margin, as discussed above, a larger current tax recovery, and a realized risk management gain on foreign exchange contracts due to hedging activity undertaken to support the Acquisition, partially offset by a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition and an increase in realized foreign exchange losses on working capital items.

The change in non-cash working capital for the three months ended September 30, 2017 was due to a decline in accounts payable, a decrease in income tax payable and an increase in accounts receivable. For the three months ended September 30, 2016, the change in non-cash working capital was due to a decline in accounts payable, a decrease in income tax payable, and a reduction in accounts receivable.

The change in non-cash working capital for the nine months ended September 30, 2017 was primarily due to a decline in accounts receivable and a reduction in inventory, partially offset by a decrease in accounts payable and an increase in income tax receivable. For the nine months ended September 30, 2016, the change in non-cash working capital was primarily due to a rise in inventory and an increase in accounts receivable, partially offset by an increase in accounts payable.

Cash From Operating Activities From Continuing Operations and Adjusted Funds Flow From Continuing Operations

Cash From Operating Activities From Continuing Operations and Adjusted Funds Flow From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Cash From Operating Activities From Continuing Operations	**481**	189	**1,778**	404
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(15)**	(8)	**(59)**	(47)
Net Change in Non-Cash Working Capital	**(371)**	(99)	**137**	(132)
Adjusted Funds Flow From Continuing Operations	**867**	296	**1,700**	583

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, revaluation gain, 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.

Total Operating Earnings

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Earnings (Loss), Before Income Tax (1)	**(311)**	(406)	**3,291**	(1,089)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss (2)	**486**	7	**75**	440
Non-Operating Unrealized Foreign Exchange (Gain) Loss (3)	**(367)**	52	**(702)**	(343)
Revaluation (Gain)	**-**	-	**(2,524)**	-
(Gain) Loss on Divestiture of Assets	**(1)**	5	**-**	6
Loss on Discontinuance	**603**	-	**603**	-
Operating Earnings (Loss), Before Income Tax	**410**	(342)	**743**	(986)
Income Tax Expense (Recovery)	**70**	(106)	**44**	(288)
Operating Earnings (Loss)	**340**	(236)	**699**	(698)

(1) Includes discontinued operations.
(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(3) 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 increased in the three months ended September 30, 2017 compared with 2016 primarily due to higher Cash from Operating Activities and Adjusted Funds Flow, as discussed above, a decrease in depreciation, depletion and amortization ("DD&A"), higher unrealized foreign exchange gains on operating items, and the re-measurement of the contingent payment.

Operating Earnings increased in the nine months ended September 30, 2017 compared with 2016 primarily due to higher Cash from Operating Activities and Adjusted Funds Flow, as discussed above, a decrease in DD&A, unrealized foreign exchange gains on operating items compared with unrealized foreign exchange losses in 2016 and the re-measurement of the contingent payment.

Operating Earnings From Continuing Operations

Operating Earnings From Continuing Operations excludes results from our Conventional segment, which has been classified as a discontinued operation.

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Earnings (Loss) From Continuing Operations, Before Income Tax	**178**	(121)	**3,701**	(527)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [(1)]	**486**	7	**75**	440
Non-Operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**(367)**	52	**(702)**	(343)
Revaluation (Gain)	**-**	-	**(2,524)**	-
(Gain) Loss on Divestiture of Assets	**(1)**	5	**-**	6
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**296**	(57)	**550**	(424)
Income Tax Expense (Recovery)	**43**	(17)	**(8)**	(112)
Operating Earnings (Loss) From Continuing Operations	**253**	(40)	**558**	(312)

(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.

Net Earnings

($ millions)	Three Months Ended	Nine Months Ended
Net Earnings (Loss) for the Periods Ended September 30, 2016	**(251)**	**(636)**
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**764**	**1,242**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(479)**	**365**
Unrealized Foreign Exchange Gain (Loss)	**490**	**567**
Revaluation Gain	**-**	**2,524**
Re-measurement of Contingent Payment	**43**	**109**
Gain (Loss) on Divestiture of Assets	**6**	**6**
Expenses [(1)]	**(220)**	**(97)**
DD&A	**(305)**	**(489)**
Exploration Expense	**-**	**1**
Income Tax Recovery (Expense)	**44**	**(898)**
Net Earnings (Loss) From Discontinued Operations	**(161)**	**88**
Net Earnings (Loss) for the Periods Ended September 30, 2017	**(69)**	**2,782**

(1) Includes realized risk management (gains) losses, general and administrative, finance costs, interest income, realized foreign exchange (gains) losses, transaction costs, research costs, other (income) loss, net, and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

Net loss for the three and nine months ended September 30, 2017 includes a $440 million after-tax loss on the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project. Net loss in the third quarter decreased compared with 2016 primarily due to:

- Higher Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of $367 million primarily related to the translation of our U.S. dollar denominated debt compared with unrealized losses of $52 million in 2016; and
- A deferred income tax recovery compared with an expense in 2016.

These decreases to our net loss were partially offset by unrealized risk management losses of $486 million compared with $7 million in the third quarter of 2016.

Net earnings improved significantly for the nine months ended September 30, 2017 primarily due to:

- The revaluation gain of $2,524 million related to the deemed disposition of our pre-existing interest in FCCL;
- Higher Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange gains of $702 million compared with $343 million in 2016; and
- Unrealized risk management losses of $75 million compared with $440 million in 2016.

These increases were partially offset by a deferred income tax expense primarily due to the gain on the revaluation of our pre-existing interest in FCCL compared with a recovery in 2016.

Net Capital Investment

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Oil Sands	**273**	110	**660**	476
Deep Basin	**64**	-	**77**	-
Conventional	**42**	41	**180**	114
Refining and Marketing	**38**	51	**124**	156
Corporate and Eliminations	**21**	6	**37**	21
Capital Investment	**438**	208	**1,078**	767
Acquisitions (1)	**70**	-	**18,301**	11
Divestitures (1)	**(943)**	(8)	**(943)**	(8)
Net Capital Investment (2)	**(435)**	200	**18,436**	770

(1) In connection with the Acquisition that was completed in the second quarter of 2017, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3 "Business Combinations" ("IFRS 3"), which is not reflected in the table above. The carrying value of the pre-existing interest was $9,081 million and the estimated fair value was $11,605 million as at May 17, 2017.
(2) Includes expenditures on PP&E, E&E assets and, assets held for sale.

Capital investment in the three and nine months ended September 30, 2017 increased $230 million and $311 million, respectively, compared with 2016. On a year-to-date basis in 2017, Oil Sands capital investment focused on sustaining capital related to existing production; Christina Lake expansion phase G; and stratigraphic test wells to determine pad placement for sustaining wells, near-term expansion phases, and progression of certain emerging assets. Deep Basin capital investment for the 137 days of ownership related to asset development planning and the commencement of our horizontal drilling program, targeting liquids rich gas within the Deep Basin corridor. In 2017, Conventional capital investment focused on sustaining capital and the tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of our Conventional assets. Capital investment in the Refining and Marketing segment related to capital maintenance and reliability work.

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

Capital Investment Decisions

In the short-term, we are acutely focused on completing the divestiture of our legacy Conventional assets in order to deleverage our balance sheet. To date, we have announced divestitures totaling approximately $2.8 billion in gross proceeds. We closed the first divestiture, Pelican Lake and the adjacent Grand Rapids project, in the third quarter of 2017 and have used the net proceeds to pay down the committed Bridge Facility. In addition to our commitment to reduce our debt, we are actively identifying cost savings opportunities.

With balance sheet leverage more in line with our strategy, our long-term disciplined approach to capital allocation includes prioritizing our uses of cash in the following manner:

- First, to sustaining and maintenance capital for our existing business operations;
- Second, to paying our current 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 with the objective 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 flows. 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.

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Adjusted Funds Flow (1)	**982**	422	**2,097**	888
Capital Investment (Sustaining and Growth)	**438**	208	**1,078**	767
Free Funds Flow (1) (2)	**544**	214	**1,019**	121
Cash Dividends	**62**	41	**164**	124
	482	173	**855**	(3)

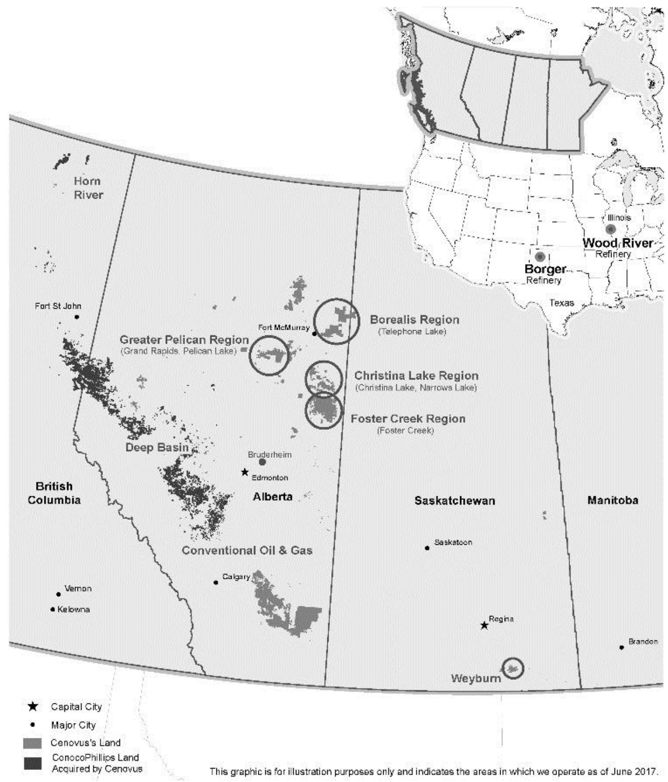
(1) Includes discontinued operations.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

For the nine months ended September 30, 2016, capital investment and cash dividends in excess of Adjusted Funds Flow was funded through our cash balance on hand.

We updated our 2017 guidance estimates upon further review of our capital program to reflect ongoing cost savings, efficiency improvements, divestiture activities, and our continued focus on capital discipline. Capital spend for 2017 is now expected to be between approximately $1.55 billion and $1.65 billion, a reduction of six percent from July 26, 2017.

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 Telephone Lake. Our interest in certain of our operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake increased from 50 percent to 100 percent on May 17, 2017.

Deep Basin, which includes approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and natural gas liquids. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. The Deep Basin Assets were acquired on May 17, 2017.

Conventional, which has been classified as a discontinued operation as we commenced marketing for sale our Conventional assets. This segment 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 CO_2 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 reportable 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 (1)

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Oil Sands (2)	**2,156**	789	**4,821**	1,965
Deep Basin (3)	**187**	-	**303**	-
Refining and Marketing	**2,161**	2,245	**7,162**	5,962
Corporate and Eliminations	**(118)**	(89)	**(322)**	(245)
	4,386	2,945	**11,964**	7,682

(1) In the second quarter of 2017, we announced our intention to divest the Conventional segment assets. As a result, the Conventional segment was classified as a discontinued operation. For the three and nine months ended September 30, 2017, revenues related to discontinued operations were $286 million and $946 million, respectively (2016 – $295 million and $810 million, respectively).

(2) Our 2017 results include 137 days of FCCL operations at 100 percent. See the Oil Sands segment section of this MD&A for more details.

(3) Our 2017 results include 137 days of operations from the Deep Basin Assets. See the Deep Basin segment section of this MD&A for more details.

OIL SANDS

In northeastern Alberta, we now own 100 percent of the Foster Creek, Christina Lake and Narrows Lake oil sands projects following the completion of the Acquisition. We have several emerging projects in the early stages of development, including our 100 percent-owned project at Telephone Lake. 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 2017 compared with 2016 include:

- More than doubling our crude oil production primarily due to the Acquisition and incremental production volumes from Christina Lake phase F and Foster Creek phase G, both of which started-up in the second half of 2016;
- Crude oil netbacks, excluding realized risk management activities, of $24.73 per barrel, a 55 percent increase from the third quarter of 2016; and
- Generating Operating Margin net of capital investment of $551 million, an increase of $394 million.

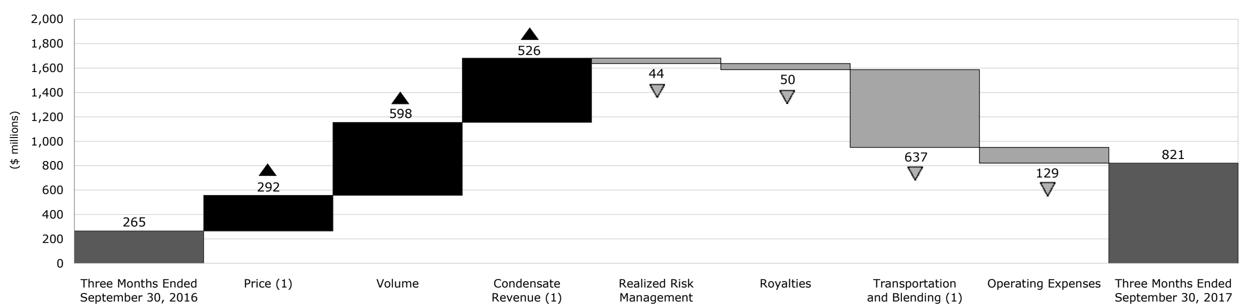
Oil Sands – Crude Oil

Three Months Ended September 30, 2017 Compared With September 30, 2016

Financial Results

($ millions)	Three Months Ended September 30, 2017	2016
Gross Sales	**2,204**	788
Less: Royalties	**54**	4
Revenues	**2,150**	784
Expenses		
Transportation and Blending	**1,066**	429
Operating	**254**	125
(Gain) Loss on Risk Management	**9**	(35)
Operating Margin	**821**	265
Capital Investment	**270**	107
Operating Margin Net of Related Capital Investment	**551**	158

Operating Margin 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

Price

In the third quarter of 2017, our average crude oil sales price increased to $40.02 per barrel (2016 – $31.30 per barrel). The rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend ("CDB") benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US$1.47 per barrel (2016 – discount of US$2.05 per barrel).

Our crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate increases relative to the price of blended crude oil, our bitumen sales price decreases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation 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 expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

(barrels per day)	Three Months Ended September 30, 2017	Percent Change	2016
Foster Creek	**154,363**	**109%**	73,798
Christina Lake	**208,131**	**161%**	79,793
	362,494	**136%**	153,591

Production at Foster Creek was higher compared with 2016 primarily due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues which were resolved by the end of the quarter.

Production from Christina Lake increased in the three months ended September 30, 2017 compared with 2016 primarily due to the Acquisition and incremental production volumes from the phase F expansion.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential during the third quarter of 2017, the proportion of the cost of condensate recovered increased. The amount of condensate used increased as a result of the Acquisition.

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. In 2017, our royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2016.

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

Effective Royalty Rates

(percent)	Three Months Ended September 30, 2017	2016
Foster Creek	**9.1**	0.8
Christina Lake	**1.6**	1.6

Royalties increased $50 million in the third quarter compared with 2016, primarily due to a higher WTI benchmark price (which determines the royalty rate), rise in sales volumes, and an increase in crude oil sales prices. As noted above, the Foster Creek royalty calculation was based on net profits as compared with a calculation based on gross revenues for 2016, resulting in a significant increase in the royalty rate.

Expenses

Transportation and Blending

Transportation and blending costs increased $637 million. Blending costs increased due to a rise in condensate volumes required for our increased production and higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price in the third quarter of 2017, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Transportation costs increased primarily due to higher sales volumes as a result of the Acquisition and incremental production volumes from the expansion phases. To help ensure adequate capacity for our expected production growth, we have capacity commitments in excess of our current production. Production growth is expected to reduce our per-barrel transportation costs.

In addition, rail costs rose as a result of moving higher volumes by rail and transporting more volumes longer distances to U.S. markets. We transported an average of 9,958 barrels per day of crude oil by rail (2016 – 7,573 barrels per day).

Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs rose due to an increase in rail costs related to higher volumes shipped to the U.S. by unit trains, partially offset by an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs.

At Christina Lake, transportation costs decreased primarily due to a revision to prior period toll charges and an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs.

Operating

Primary drivers of our operating expenses for the third quarter of 2017 were workforce costs, fuel, chemical costs, workovers and repairs and maintenance. Total operating expenses increased $129 million primarily due to the Acquisition, partially offset by a decline in fuel costs associated with a decrease in the natural gas price.

Per-unit Operating Expenses

	Three Months Ended September 30,		
($/bbl)	**2017**	**Percent Change**	2016
Foster Creek			
Fuel	**2.10**	**(14)%**	2.44
Non-fuel	**7.43**	**3%**	7.19
Total	**9.53**	**(1)%**	9.63
Christina Lake			
Fuel	**1.78**	**(17)%**	2.14
Non-fuel	**4.30**	**(23)%**	5.58
Total	**6.08**	**(21)%**	7.72
Total	**7.58**	**(12)%**	8.65

At Foster Creek, per-barrel fuel costs decreased compared with 2016 primarily due to lower natural gas prices. Per-barrel non-fuel operating expenses increased primarily due to increased workover activities due to pump changes, partially offset by an increase in production.

At Christina Lake, fuel costs decreased on a per-barrel basis in 2017 primarily due to lower fuel consumption. Non-fuel per-barrel operating expenses declined primarily due to higher production, partially offset by higher workforce and chemicals costs associated with the phase F expansion, increased workover activities due to pump changes, and increased repairs and maintenance activities.

Netbacks (1)

	Foster Creek		**Christina Lake**	
	Three Months Ended September 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**41.57**	33.61	**38.84**	29.11
Royalties	**2.98**	0.19	**0.55**	0.41
Transportation and Blending	**8.68**	8.38	**4.14**	4.49
Operating Expenses	**9.53**	9.63	**6.08**	7.72
Netback Excluding Realized Risk Management	**20.38**	15.41	**28.07**	16.49
Realized Risk Management Gain (Loss)	**(0.13)**	2.37	**(0.40)**	2.38
Netback Including Realized Risk Management	**20.25**	17.78	**27.67**	18.87

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Risk Management

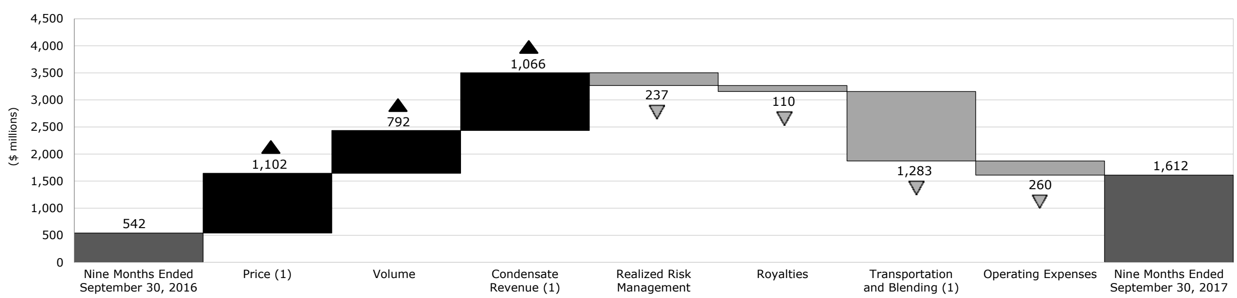
Risk management activities in the third quarter of 2017 resulted in realized losses of $9 million (2016 – realized gains of $35 million), consistent with average benchmark prices exceeding our contract prices.

Nine Months Ended September 30, 2017 Compared With September 30, 2016

Financial Results

($ millions)	Nine Months Ended September 30, 2017	2016
Gross Sales	**4,920**	1,960
Less: Royalties	**117**	7
Revenues	**4,803**	1,953
Expenses		
Transportation and Blending	**2,511**	1,228
Operating	**608**	348
(Gain) Loss on Risk Management	**72**	(165)
Operating Margin	**1,612**	542
Capital Investment	**654**	472
Operating Margin Net of Related Capital Investment	**958**	70

Operating Margin 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

Price

In the nine months ended September 30, 2017, our average crude oil sales price increased significantly to $39.52 per barrel (2016 – $24.28 per barrel). The significant rise in our crude oil price was consistent with the increase in the WCS and CDB benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US$1.60 per barrel (2016 – discount of US$2.22 per barrel).

Production Volumes

(barrels per day)	Nine Months Ended September 30, 2017	Percent Change	2016
Foster Creek	**114,632**	**73%**	66,435
Christina Lake	**154,634**	**97%**	78,321
	269,266	**86%**	144,756

Production at Foster Creek was higher compared with 2016 due to the Acquisition and incremental production volumes from the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues and a 20-day planned turnaround which reduced average production by 3,690 barrels per day. The planned turnaround was the largest scale turnaround executed to date at Foster Creek.

Production from Christina Lake increased in the nine months ended September 30, 2017 primarily due to the Acquisition and incremental production volumes from the phase F expansion.

The year-to-date increase in production volumes at Foster Creek and Christina Lake due to the Acquisition was 38,203 barrels per day and 52,685 barrels per day, respectively.

Royalties

Effective Royalty Rates

(percent)	Nine Months Ended September 30, 2017	2016
Foster Creek	**8.4**	0.5
Christina Lake	**2.1**	1.4

Royalties increased $110 million. Royalties at Foster Creek increased primarily due to a higher WTI benchmark price (which determines the royalty rate). The royalty calculation was based on net profits as compared with a calculation based on gross revenues for 2016, resulting in a significant increase in the royalty rate. In 2016, the low royalty rate was primarily due to low crude oil sales prices and a true-up of the 2015 royalty calculation.

Christina Lake royalties increased in 2017 primarily as a result of a rise in the WTI benchmark price (which determines the royalty rate), higher sales prices and an increase in sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs increased $1,283 million. Blending costs increased due to a rise in condensate volumes required for our increased production along with higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price in the nine months ended September 30, 2017, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Transportation costs increased primarily due to higher sales volumes related to the incremental production volumes from the Acquisition and expansion phases.

In addition, rail costs rose as a result of moving higher volumes by rail over longer distances to U.S. markets. We transported an average of 7,842 barrels per day of crude oil by rail (2016 – 5,106 barrels per day).

Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs declined primarily due to an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs, partially offset by an increase in rail costs related to an increase in volumes shipped to the U.S. by unit trains.

At Christina Lake, transportation costs decreased primarily due to an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs, and a revision to prior period toll charges.

Operating

Primary drivers of our operating expenses in the nine months ended September 30, 2017 were workforce costs, fuel, repairs and maintenance, chemical costs and workovers. Total operating expenses increased $260 million primarily due to the Acquisition, higher fuel costs with the rise in natural gas prices, additional repairs and maintenance, and fluid, waste handling and trucking costs related to the turnaround at Foster Creek and increased workforce and chemical costs associated with the phase F expansion at Christina Lake.

Per-unit Operating Expenses

	Nine Months Ended September 30,		
($/bbl)	2017	Percent Change	2016
Foster Creek			
Fuel	**2.53**	**15%**	2.20
Non-fuel	**7.96**	**(4)%**	8.32
Total	**10.49**	**-%**	10.52
Christina Lake			
Fuel	**2.14**	**16%**	1.85
Non-fuel	**4.66**	**(14)%**	5.39
Total	**6.80**	**(6)%**	7.24
Total	**8.40**	**(4)%**	8.74

At Foster Creek, per-barrel fuel costs increased primarily due to the rise in natural gas prices. Per-barrel non-fuel operating expenses declined primarily due to higher production, partially offset by higher repairs and maintenance, and fluid, waste handling and trucking costs related to turnaround activities, and an increase in workover costs due to pump changes.

At Christina Lake, fuel costs rose on a per-barrel basis due to a rise in natural gas prices, partially offset by a decrease in fuel consumption. Per-barrel non-fuel operating expenses decreased primarily due to higher production, partially offset by increased workforce and chemical costs associated with the phase F expansion, and higher repairs and maintenance activities.

Netbacks [1]

	Foster Creek		Christina Lake	
	Nine Months Ended September 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**42.22**	26.97	**37.47**	22.01
Royalties	**2.80**	0.10	**0.71**	0.25
Transportation and Blending	**9.01**	9.43	**4.12**	4.89
Operating Expenses	**10.49**	10.52	**6.80**	7.24
Netback Excluding Realized Risk Management	**19.92**	6.92	**25.84**	9.63
Realized Risk Management Gain (Loss)	**(1.05)**	4.37	**(0.96)**	3.95
Netback Including Realized Risk Management	**18.87**	11.29	**24.88**	13.58

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Risk Management

Risk management activities on a year-to-date basis in 2017 resulted in realized losses of $72 million (2016 – realized gains of $165 million), consistent with average benchmark prices exceeding our contract prices.

Oil Sands – Natural Gas

Oil Sands includes 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, 2017, net of internal usage, was 6 MMcf per day and 11 MMcf per day, respectively (2016 – 18 MMcf per day and 17 MMcf per day, respectively).

Operating Margin from our Oil Sands natural gas production was $nil in the third quarter of 2017, a decrease of $3 million compared with 2016, due to lower natural gas sales prices and a decline in natural gas volumes. On a year-to-date basis, the Operating Margin was $3 million, a decrease of $1 million compared with 2016, due to lower natural gas volumes, partially offset by higher natural gas sales prices.

Oil Sands – Capital Investment

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Foster Creek	**122**	54	**312**	211
Christina Lake	**132**	47	**272**	222
	254	101	**584**	433
Narrows Lake	**3**	1	**11**	6
Telephone Lake	**3**	3	**32**	13
Grand Rapids	**-**	-	**1**	5
Other [1]	**13**	5	**32**	19
Capital Investment [2]	**273**	110	**660**	476

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

Existing Projects

Capital investment reflects our 100 percent ownership of FCCL from May 17, 2017 forward. Capital investment at Foster Creek in 2017 focused on sustaining capital related to existing production and stratigraphic test wells. In 2016, capital investment was low due to spending reductions in response to the low commodity price environment. Capital was also invested in 2016 to complete Foster Creek phase G.

In 2017, Christina Lake capital investment related to sustaining capital related to existing production, the phase G expansion and stratigraphic test wells. In 2016, capital was focused on sustaining capital related to existing production, the completion of expansion phase F and stratigraphic test wells.

Capital investment at Narrows Lake on a year-to-date basis in 2017 related to drilling of stratigraphic test wells to further progress the project.

Emerging Projects

In 2017, Telephone Lake capital investment concentrated on the drilling of stratigraphic test wells to further assess the project. In 2016, spending was reduced in response to the low commodity price environment and focused on front-end engineering work for the central processing facility.

Drilling Activity

Nine Months Ended September 30,	Gross Stratigraphic Test Wells 2017	Gross Stratigraphic Test Wells 2016	Gross Production Wells (1) 2017	Gross Production Wells (1) 2016
Foster Creek	**93**	95	**25**	18
Christina Lake	**105**	97	**8**	24
	198	192	**33**	42
Narrows Lake	**2**	-	**-**	-
Telephone Lake	**13**	-	**-**	-
Other	**1**	5	**-**	-
	214	197	**33**	42

(1) SAGD well pairs are counted as a single producing well.

Stratigraphic test wells were drilled to help identify well pad locations for sustaining wells and near-term expansion phases and to further progress the evaluation of emerging assets.

Future Capital Investment

We updated our 2017 guidance estimates upon further review of our capital program. Our revised full-year 2017 Oil Sands capital investment is forecast to be between $945 million and $1,015 million. Guidance has decreased from July 26, 2017 by approximately eight percent to reflect ongoing cost savings, efficiency improvements and our continued focus on capital discipline.

Foster Creek is currently producing from phases A through G. Capital investment for 2017 is forecast to be between $450 million and $475 million. We plan to continue focusing on sustaining capital related to existing production and to progress phase H, a potential 40,000 barrels per day phase, towards being sanction ready.

Christina Lake is producing from phases A through F. Capital investment for 2017 is forecast to be between $425 million and $450 million, focused on sustaining capital and construction of the phase G expansion. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, is progressing well and remains on track. Phase G is expected to start producing in the second half of 2019.

Capital investment at our Narrows Lake and new resource plays in 2017 is forecast to be between $70 million and $90 million, focusing on stratigraphic test well programs at Telephone Lake and engineering and equipment preservation related to the suspension of construction at Narrows Lake.

DD&A and Exploration Expense

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 total upstream assets could be determined using the reported consolidated data and includes our Conventional segment, which has been classified as held for sale. Once classified as held for sale depletion stops.

($ millions, unless otherwise indicated)	As at December 31, 2016
Upstream Property, Plant and Equipment Carrying Value	**11,878**
Estimated Future Development Capital	**18,378**
Total Estimated Upstream Cost Base	**30,256**
Total Proved Reserves (MMBOE)	**2,667**
Implied Depletion Rate ($/BOE)	**11.34**

While this illustrates the calculation of the implied depletion rate, our depletion rates result in a total average rate ranging between $9.55 to $10.00 per BOE. Amounts related to assets under construction and discontinued operations 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 December 31, 2016 Consolidated Financial Statements.

In the three and nine months ended September 30, 2017, Oil Sands DD&A increased $212 million and $351 million, respectively, from 2016. The increase was due to higher sales volumes primarily due to the Acquisition. The average depletion rate on a year-to-date basis in 2017 was approximately $11.24 per barrel compared with $11.55 per barrel in 2016. Our DD&A rate decreased due to proved reserves additions and lower future development costs. The decrease in DD&A rates was partially offset by an increase in the carrying value of our assets due to the re-measurement of our pre-existing interest in FCCL and the acquisition of the additional 50 percent interest.

Future development costs declined due to cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs and increased well pair spacing. This decline was partially offset by an increase in costs related to the expansion of the development area and inclusion of phase G costs at Christina Lake.

For the three and nine months ended September 30, 2017, we recorded exploration expense of $1 million (2016 – $1 million and $2 million, respectively).

Assets and Liabilities Held for Sale

On September 29, 2017, we closed the sale of our Pelican Lake assets, including the adjacent Grand Rapids project.

DEEP BASIN

On May 17, 2017, we acquired the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets including undeveloped land, exploration and production assets, and related infrastructure in Alberta and British Columbia. Our Deep Basin Assets include approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, with an average 70 percent working interest. In addition, the Deep Basin Assets include interests in numerous natural gas processing plants with an estimated net processing capacity of 1.4 Bcf per day. The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. Deep Basin production is expected to provide an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations, as well as NGLs that could be used as inputs for future solvent aided oil sands projects.

The safe and efficient integration of the Deep Basin Assets continues to be a top priority for Cenovus. We are committed to ensuring strong stakeholder and community relations as we establish ourselves as a new operator in the Deep Basin area.

Significant developments that impacted our Deep Basin segment in the third quarter of 2017 included:

- Total capital investment of $64 million related to the drilling of 10 horizontal production wells targeting liquids rich gas, the completion of four wells, and the tie-in of three wells;
- Netbacks of $5.34 per BOE;
- Total production averaging 115,301 BOE per day;
- Revenues of $187 million; and
- Total operating costs of $101 million or $9.00 per BOE.

Financial Results

($ millions)	Three Months Ended September 30, 2017	May 17 – September 30, 2017
Gross Sales	**200**	**324**
Less: Royalties	**13**	**21**
Revenues	**187**	**303**
Expenses		
Transportation and Blending	**22**	**32**
Operating	**101**	**152**
Operating Margin	**64**	**119**
Capital Investment	**64**	**77**
Operating Margin Net of Related Capital Investment	**-**	**42**

Revenues

Price

	Three Months Ended September 30, 2017	May 17 – September 30, 2017
NGLs ($/bbl)	**30.78**	**29.57**
Light and Medium Oil ($/bbl)	**52.54**	**55.64**
Natural Gas ($/mcf)	**1.77**	**2.15**
Total Oil Equivalent ($/BOE)	**17.61**	**19.07**

Our Deep Basin Assets produce a variety of products from natural gas, condensate, other NGLs (including ethane, propane, butane and pentane) and light and medium oil.

For the three and nine months ended September 30, 2017, revenues include $13 million and $19 million, respectively, of processing fee revenue related to our interests in natural gas processing facilities. We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	Three Months Ended September 30, 2017	Nine Months Ended September 30, 2017
Liquids		
NGLs (barrels per day)	**26,370**	**13,498**
Light and Medium Oil (barrels per day)	**6,494**	**3,208**
	32,864	**16,706**
Natural Gas (MMcf per day)	**495**	**251**
Total Production (BOE/per day)	**115,301**	**58,516**
Natural Gas Production (percentage of total)	**71%**	**71%**
Liquids Production (percentage of total)	**29%**	**29%**

Total production from the date of Acquisition to September 30, 2017 was 116,605 BOE per day, equivalent to 58,516 BOE per day for the nine months ended September 30, 2017.

Royalties

The Deep Basin Assets are subject to royalty regimes in both Alberta and British Columbia. In Alberta, royalties benefit from a number of different programs that reduce the royalty rate on natural gas production. Natural gas wells in Alberta also benefit from the Gas Cost Allowance ("GCA"), which reduces royalties, to account for capital and operating costs incurred to process and transport the Crown's portion of natural gas production.

Effective January 1, 2017, the Alberta Government released a new Royalty Regime, Alberta's Modernized Royalty Framework ("MRF"), which applies to all producing wells after January 1, 2017. Under this new framework, Cenovus will pay a five percent pre-payout royalty on all production until the total revenue from a well equals the drilling and completion cost allowance calculated for each well that meets certain MRF criteria. Subsequently, a higher post-payout royalty rate will apply and will vary based on product-specific market prices. Once a well reaches a maturity threshold, the royalty rate will drop to better match declining production rates. Wells drilled before January 1, 2017 will be managed under the old framework until 2027 and then will convert to the MRF.

In British Columbia, royalties also benefit from programs to reduce the rate on natural gas production. British Columbia applies a GCA, but only on natural gas processed through producer-owned plants. British Columbia also offers a Producer Cost of Service allowance, which reduces the royalty for the processing of the Crown's portion of natural gas production.

For the three and nine months ended September 30, 2017, the effective liquids royalty rate was 11.4 percent. In the third quarter and on a year-to-date basis in 2017, the effective natural gas royalty rate was 3.5 percent and 3.7 percent, respectively.

Expenses

Transportation

For the three and nine months ended September 30, 2017, transportation costs were $1.96 per BOE. Transportation expenses include charges for the transportation of crude oil, natural gas and NGLs to the sales point.

Operating

Primary drivers of our operating expenses for the third quarter and on a year-to-date basis related to repairs and maintenance, workforce costs, processing fee expense, and property tax and lease costs. In the third quarter and on a year-to-date basis, operating costs were $9.00 per BOE and $8.95 per BOE, respectively.

Netbacks

($/BOE)	Three Months Ended September 30, 2017	May 17 – September 30, 2017
Sales Price	**17.61**	**19.07**
Royalties	**1.28**	**1.34**
Transportation and Blending	**1.96**	**1.96**
Operating Expenses	**9.00**	**8.95**
Production and Mineral Taxes	**0.03**	**0.03**
Netback	**5.34**	**6.79**

Deep Basin – Capital Investment

In the Deep Basin, we are taking a disciplined approach to development activities. In 2017, capital investment is focused on the drilling and completion of horizontal production wells targeting liquids rich gas within the Deep Basin corridor.

($ millions)	May 17 – September 30, 2017
Drilling and Completions	47
Facilities	11
Other	19
Capital Investment [(1)]	**77**

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

Drilling Activity

(net wells, unless otherwise stated)	May 17 - September 30, 2017
Drilled	10
Completed	4
Tied-in	3

Future Capital Investment

Our 2017 Deep Basin capital investment is forecast to be between $160 million and $180 million.

We are taking a disciplined development approach on the Deep Basin Assets through 2017 and anticipate ramping up our activity levels through 2020. We plan to focus capital investment on a number of drilling opportunities that have the potential to generate strong returns and start to use facilities that are currently underutilized.

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. Deep Basin DD&A for the three and nine months ended September 30, 2017 was $91 million and $136 million, respectively.

CONVENTIONAL (DISCONTINUED OPERATIONS)

Our divestiture plans for our legacy Conventional assets are well underway. On September 29, 2017, we closed the sale of our Pelican Lake assets, including the adjacent Grand Rapids project, for gross cash proceeds of $975 million. On September 25, 2017, we announced the sale of our Suffield crude oil and natural gas assets in southern Alberta for gross cash proceeds of $512 million, plus a DPPA. As at September 30, 2017, the fair value of the DPPA was estimated to be between $5 million and $10 million. On October 19, 2017, we announced the divestiture of our Palliser crude oil and natural gas operations in southern Alberta for gross cash proceeds of $1.3 billion. Both sales are expected to close in the fourth quarter, subject to customary closing conditions. The sales process for our CO_2 enhanced oil recovery project at Weyburn is progressing as planned and we expect to make a further divestiture announcement in the fourth quarter. The established assets in this segment have long life reserves, stable operations and produce a diversity of crude oil.

Significant developments that impacted our Conventional segment in the third quarter of 2017 compared with 2016 include:

- Recording a loss of $603 million on the sale of our Pelican Lake assets and the adjacent Grand Rapids project;
- Our average liquids sales price increasing 13 percent to $49.79 per barrel;
- Liquids and natural gas Netbacks, excluding realized risk management activities, of $20.37 per barrel (2016 – $20.63 per barrel) and $0.53 per Mcf (2016 – $1.25 per Mcf), respectively;
- Liquids production averaging 53,697 barrels per day, declining slightly from 2016 primarily due to expected natural declines, partially offset by an increase in production associated with the tight oil drilling program in southern Alberta; and
- Generating Operating Margin net of capital investment of $75 million, a decrease of 32 percent.

The third quarter Conventional results include our Suffield and Pelican Lake assets.

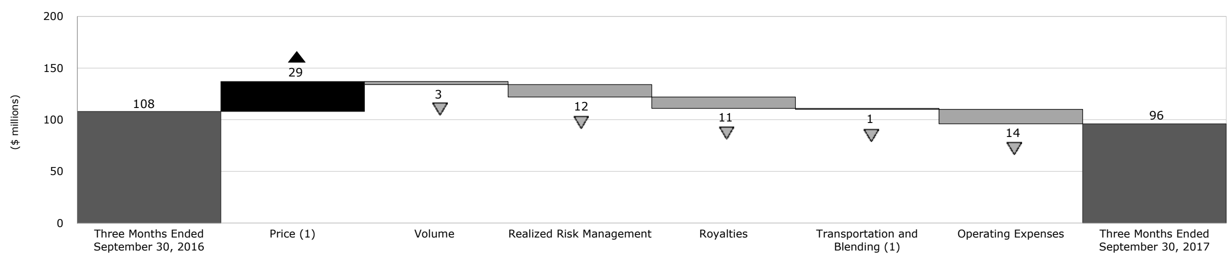
Conventional – Liquids

Three Months Ended September 30, 2017 Compared With September 30, 2016

Financial Results

($ millions)	Three Months Ended September 30, 2017	2016
Gross Sales	**268**	242
Less: Royalties	**43**	32
Revenues	**225**	210
Expenses		
Transportation and Blending	**41**	40
Operating	**79**	65
Production and Mineral Taxes	**4**	4
(Gain) Loss on Risk Management	**5**	(7)
Operating Margin	**96**	108
Capital Investment	**41**	39
Operating Margin Net of Related Capital Investment	**55**	69

Operating Margin 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

Price

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

Our liquids sales price averaged $49.79 per barrel in the third quarter of 2017, a 13 percent increase from 2016, due to higher crude oil benchmark prices, adjusted for applicable differentials, and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. 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 average 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 expect to 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

(barrels per day)	Three Months Ended September 30, 2017	Percent Change	2016
Heavy Oil	**25,549**	**(9)%**	28,096
Light and Medium Oil	**26,947**	**6%**	25,311
NGLs	**1,201**	**12%**	1,074
	53,697	**(1)%**	54,481

Total production declined slightly in 2017 compared with 2016 primarily as a result of expected natural declines, partially offset by an increase in light and medium oil associated with our tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

Condensate

The heavy oil currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Our blending ratios for Conventional heavy oil range between 10 percent and 16 percent. Revenues represent the total value of blended crude oil sold and includes the value of condensate. Consistent with the narrowing of the WCS-Condensate differential in the third quarter of 2017, the proportion of the cost of condensate recovered increased.

Royalties

Conventional liquids royalties increased primarily due to higher royalty rates and an increase in our sales prices, partially offset by a decline in sales volumes. In the third quarter of 2017, the effective liquids royalty rate for our Conventional properties was 19.0 percent (2016 – 15.8 percent).

Crown royalties at Pelican Lake are determined under oil sands royalty calculations. Pelican Lake is a post-payout project, therefore royalties are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs. The Pelican Lake crown royalty calculation was based on net profits in 2017 and 2016.

Expenses

Transportation and Blending

Transportation and blending costs increased slightly in the third quarter of 2017. Transportation charges were higher due to increased costs associated with optimizing our sales, partially offset by a decline in sales volumes. Blending costs were relatively consistent as higher condensate prices were mostly offset by a decrease in condensate volumes.

Operating

Primary drivers of our operating expenses in the third quarter of 2017 were workover activities, workforce costs, electricity, property taxes and lease costs, and repairs and maintenance. Operating costs increased 24 percent to $16.02 per barrel primarily due to:

- A rise in workover costs, repairs and maintenance, and fluid, waste handling and trucking costs as a result of increased activity; and
- An increase in electricity costs.

In the third quarter of 2017, production and mineral taxes were consistent with 2016.

Netbacks [(1)]

	Heavy Oil		Light and Medium Oil	
	Three Months Ended September 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**48.01**	40.50	**51.91**	48.97
Royalties	**7.04**	3.97	**10.22**	8.91
Transportation and Blending	**5.45**	4.86	**2.85**	2.71
Operating Expenses	**15.50**	12.43	**17.19**	13.94
Production and Mineral Taxes	**0.01**	0.01	**1.54**	1.48
Netback Excluding Realized Risk Management	**20.01**	19.23	**20.11**	21.93
Realized Risk Management Gain (Loss)	**(0.89)**	1.50	**(1.17)**	1.47
Netback Including Realized Risk Management	**19.12**	20.73	**18.94**	23.40

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Risk Management

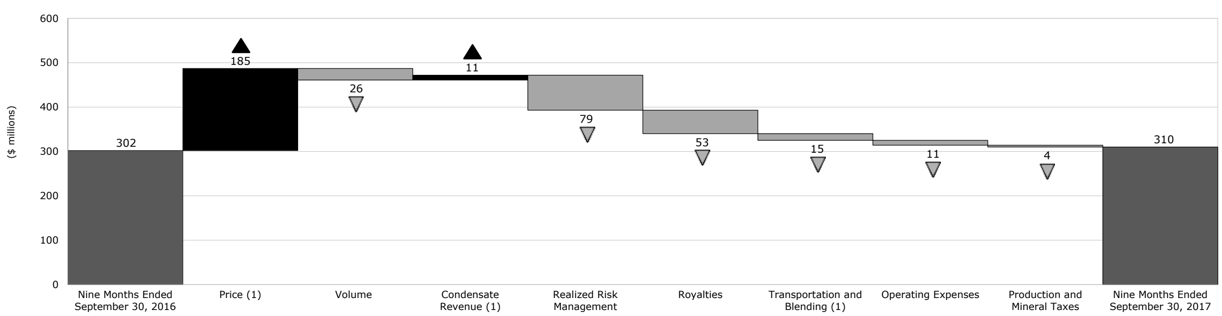
Risk management activities for the third quarter of 2017 resulted in realized losses of $5 million (2016 – realized gains of $7 million), consistent with average benchmark prices exceeding our contract prices.

Nine Months Ended September 30, 2017 Compared With September 30, 2016

Financial Results

($ millions)	Nine Months Ended September 30, 2017	2016
Gross Sales	**840**	670
Less: Royalties	**133**	80
Revenues	**707**	590
Expenses		
Transportation and Blending	**139**	124
Operating	**224**	213
Production and Mineral Taxes	**13**	9
(Gain) Loss on Risk Management	**21**	(58)
Operating Margin	**310**	302
Capital Investment	**173**	108
Operating Margin Net of Related Capital Investment	**137**	194

Operating Margin 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

Price

Our average liquids sales price increased 33 percent to $51.03 per barrel consistent with the improvement in crude oil benchmark prices, net of applicable differentials.

Production Volumes

(barrels per day)	Nine Months Ended September 30, 2017	Percent Change	2016
Heavy Oil	**26,466**	**(10)%**	29,276
Light and Medium Oil	**26,430**	**1%**	26,200
NGLs	**1,128**	**10%**	1,027
	54,024	**(4)%**	56,503

Total production decreased primarily as a result of expected natural declines, partially offset by an increase in production associated with our tight oil drilling program in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets.

Royalties

Royalties increased $53 million primarily due to an increase in our sales prices, higher royalty rates, and lower allowable costs for royalty purposes at Weyburn and Pelican Lake, partially offset by a reduction in sales volumes. For the nine months ended September 30, 2017, the effective liquids royalty rate for our Conventional properties was 19.2 percent (2016 – 14.9 percent).

Expenses

Transportation and Blending

Transportation and blending costs increased $15 million, primarily due to a rise in blending costs as a result of higher condensate prices, partially offset by a decrease in condensate volumes, consistent with lower production. Transportation charges were lower largely due to a decline in sales volumes.

Operating

Primary drivers of our operating expenses on a year-to-date basis in 2017 were workforce costs, workover activities, electricity, property taxes and lease costs and repairs and maintenance. Operating expenses increased $1.26 per barrel, to $15.17 per barrel.

The per unit increase was primarily due to lower production volumes, an increase in workover and repairs and maintenance activities, and higher energy costs. This increase was partially offset by a decrease in chemical costs associated with reduced polymer consumption.

Production and mineral taxes increased on a year-to-date basis due to the rise in crude oil prices.

Netbacks [1]

	Heavy Oil		Light and Medium Oil	
	Nine Months Ended September 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**47.46**	34.18	**54.97**	43.66
Royalties	**6.72**	3.06	**11.47**	7.50
Transportation and Blending	**4.44**	4.50	**2.79**	2.74
Operating Expenses	**14.30**	12.94	**16.68**	15.52
Production and Mineral Taxes	**0.01**	-	**1.77**	1.15
Netback Excluding Realized Risk Management	**21.99**	13.68	**22.26**	16.75
Realized Risk Management Gain (Loss)	**(1.47)**	3.98	**(1.46)**	3.88
Netback Including Realized Risk Management	**20.52**	17.66	**20.80**	20.63

(1) Netbacks reflect our margin on a per-barrel basis of unblended crude oil.

Risk Management

Risk management activities for the nine months ended September 30, 2016 resulted in realized losses of $21 million (2016 – realized gains of $58 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Gross Sales	**62**	86	**247**	221
Less: Royalties	**2**	3	**12**	8
Revenues	**60**	83	**235**	213
Expenses				
Transportation and Blending	**3**	4	**10**	12
Operating	**39**	35	**117**	113
Production and Mineral Taxes	**-**	-	**1**	-
(Gain) Loss on Risk Management	**(2)**	-	**(2)**	1
Operating Margin	**20**	44	**109**	87
Capital Investment	**1**	2	**7**	6
Operating Margin Net of Related Capital Investment	**19**	42	**102**	81

The Operating Margin from natural gas continued to help fund growth opportunities in our Oil Sands and Deep Basin segments.

Three and Nine Months Ended September 30, 2017 Compared With September 30, 2016

Revenues

Price

In the three months ended September 30, 2017, our average natural gas sales price decreased 22 percent to $1.94 per Mcf, consistent with the decline in the AECO benchmark price. On a year-to-date basis, our average natural gas sales price increased 22 percent to $2.58 per Mcf, consistent with the rise in the AECO benchmark price.

Production

Production decreased six percent to 350 MMcf per day in the third quarter of 2017. On a year-to-date basis, production declined eight percent to 351 MMcf per day due to expected natural declines.

Royalties

Royalties decreased slightly in the third quarter due to lower sales prices and production declines. On a year-to-date basis, royalties increased as a result of higher sales prices, partially offset by production declines. The average royalty rate in the third quarter and on a year-to-date basis was 5.1 percent (2016 – 4.5 percent and 4.4 percent, respectively).

Expenses

Transportation

In the three and nine months ended September 30, 2017, transportation costs declined slightly compared with 2016 primarily due to a decrease in sales volumes.

Operating

Primary drivers of our operating expenses in the three and nine months ended September 30, 2017 were property taxes and lease costs, workforce costs and repairs and maintenance. Operating expenses increased in the three and nine months ended September 30, 2017 primarily due to an increase in repairs and maintenance.

Risk Management

Risk management activities resulted in realized gains of $2 million in the third quarter and on a year-to-date basis (2016 – $nil in the third quarter and realized losses of $1 million on a year-to-date basis), consistent with our contract prices exceeding average benchmark prices.

Conventional – Capital Investment

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2017**	2016	**2017**	2016
Heavy Oil	**14**	11	**30**	34
Light and Medium Oil	**27**	28	**143**	74
Natural Gas	**1**	2	**7**	6
Capital Investment [(1)]	**42**	41	**180**	114

(1) Includes expenditures on PP&E, E&E assets, and assets held for sale.

Capital investment for the three and nine months ended September 30, 2017 was primarily related to sustaining capital and the purchase of CO_2 at Weyburn. On a year-to-date basis, capital investment also focused on our tight oil drilling opportunities in southern Alberta. We wound down our drilling program early in the third quarter due to the pending sale of these assets. Capital investment increased compared with 2016 as a result of limited crude oil capital investment activities in 2016 in response to the low commodity price environment.

Drilling Activity

	Nine Months Ended September 30,	
(net wells, unless otherwise stated)	**2017**	2016
Crude Oil	**24**	1
Recompletions	**-**	84
Gross Stratigraphic Test Wells	**26**	27

Drilling activity on a year-to-date basis in 2017 focused on drilling stratigraphic test wells and horizontal production wells for tight oil in southern Alberta.

Future Capital Investment

We updated our 2017 guidance estimates to reflect our recently completed and anticipated divestiture activities. Our revised full-year 2017 Conventional capital investment guidance is forecast to be between $210 million and $225 million, mainly related to sustaining capital, a decrease of approximately 13 percent from July 26, 2017.

DD&A and Exploration Expense

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.

No DD&A was recorded in the third quarter of 2017 due to the classification of the Conventional segment as held for sale as required by IFRS. DD&A in 2016 included impairment losses of $210 million and $65 million associated with our Northern Alberta cash-generating unit ("CGU") and Suffield CGU, respectively.

DD&A decreased $687 million on a year-to-date basis primarily due to impairment losses of $445 million recorded in 2016, the decision to divest our conventional assets, and a decline in sales volumes.

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. and operated by our partner, Phillips 66. 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 the 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, 2017, we loaded an average of 10,542 and 11,166 gross barrels per day, respectively (2016 – 15,186 and 12,487 gross barrels per day, respectively).

Refinery Operations [(1)]

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2016	**2017**	2016
Crude Oil Capacity (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**462**	463	**439**	452
Heavy Crude Oil	**213**	241	**205**	237
Light/Medium	**249**	222	**234**	215
Refined Products (Mbbls/d)	**490**	494	**467**	479
Gasoline	**239**	235	**230**	235
Distillate	**156**	152	**147**	148
Other	**95**	107	**90**	96
Crude Utilization (percent)	**100**	101	**95**	98

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

On a 100-percent basis, the Refineries have a 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 and 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI 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 optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

In the third quarter, refined product output declined compared with 2016 primarily due to unplanned maintenance at both Refineries in 2017. Lower heavy crude oil volumes were processed due to optimization of the total crude input slate as a result of narrowing heavy crude oil differentials.

On a year-to-date basis, crude oil runs and refined product output decreased compared with 2016 primarily due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2017 compared with 2016, in addition to unplanned maintenance at both Refineries in 2017. Lower heavy crude oil volumes were processed due to the planned turnarounds in the first quarter of 2017 and optimization of the total crude input slate.

Financial Results

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Revenues	**2,161**	2,245	**7,162**	5,962
Purchased Product	**1,782**	2,004	**6,295**	5,144
Gross Margin	**379**	241	**867**	818
Expenses				
Operating	**168**	172	**579**	557
(Gain) Loss on Risk Management	**-**	1	**4**	23
Operating Margin	**211**	68	**284**	238
Capital Investment	**38**	51	**124**	156
Operating Margin Net of Related Capital Investment	**173**	17	**160**	82

Gross Margin

The refining realized crack spread, which is the gross margin on a per barrel basis, is affected by many factors, such as the variety of feedstock crude oil processed; 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 the Refineries; and the cost of feedstock. Feedstock costs are valued on a FIFO accounting basis.

In the three months ended September 30, 2017, our gross margin increased primarily due to higher average market crack spreads and a rise in margins on the sale of our secondary products, such as NGLs, coke, and asphalt, due to higher realized prices. These increases in gross margin were partially offset by:

- Narrowing heavy crude oil differentials; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately $15 million on our gross margin.

In the nine months ended September 30, 2017, our gross margin rose primarily due to higher average market crack spreads, and a rise in margins on the sale of our secondary products. These increases in gross margin were partially offset by:

- Narrowing heavy crude oil differentials;
- Lower crude utilization rates; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately $9 million on our gross margin.

In the three and nine months ended September 30, 2017, the costs associated with Renewable Identification Numbers ("RINs") were $81 million and $208 million, respectively (2016 – $80 million and $209 million, respectively). The costs of RINs remained relatively consistent as the decrease in RINs benchmark prices was offset by an increase in the required RINs volume obligation.

Operating Expense

Primary drivers of operating expenses in the third quarter and on a year-to-date basis of 2017 were labour, maintenance, utilities and supplies. Reported operating expenses were lower in the third quarter compared with 2016 primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar, partially offset by an increase in labour costs. On a year-to-date basis, operating expenses increased due to higher utility costs resulting from higher natural gas prices, and an increase in maintenance costs associated with the plant turnarounds in the first quarter of 2017.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Wood River Refinery	**24**	33	**80**	108
Borger Refinery	**11**	16	**40**	42
Marketing	**3**	2	**4**	6
	38	51	**124**	156

Capital expenditures in 2017 focused on capital maintenance and reliability work. Capital investment declined in the third quarter and on a year-to-date basis compared with 2016 primarily due to the completion of work on the debottlenecking project at the Wood River refinery in the third quarter of 2016.

We updated our 2017 guidance estimates upon further review of our capital program. Our revised full-year 2017 Refining and Marketing capital investment is forecast to be between $180 million and $200 million, mainly related to capital maintenance and reliability work. Guidance has decreased from July 26, 2017 by approximately five percent to reflect our continued focus on capital discipline.

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 $1 million in the third quarter and $5 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, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains on interest rate swaps and foreign exchange contracts. In the third quarter of 2017, our risk management activities resulted in $486 million of unrealized losses (2016 – $7 million of unrealized losses). On a year-to-date basis, we incurred $75 million of unrealized risk management losses (2016 – $440 million of unrealized losses). As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. On a year-to-date basis, we realized a $142 million risk management gain on foreign exchange contracts primarily due to hedging activity undertaken to support the Acquisition.

The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, finance costs, interest income, foreign exchange (gain) loss, revaluation (gain), transaction costs, re-measurement of the contingent payment, research costs, (gain) loss on divestiture of assets, and other (income) loss.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
($ millions)	**2017**	2016	**2017**	2016
General and Administrative	**116**	71	**217**	225
Finance Costs	**191**	97	**458**	292
Interest Income	**(32)**	(27)	**(59)**	(45)
Foreign Exchange (Gain) Loss, Net	**(350)**	45	**(836)**	(338)
Revaluation (Gain)	**-**	-	**(2,524)**	-
Transaction Costs	**1**	-	**56**	-
Re-measurement of the Contingent Payment	**(43)**	-	**(109)**	-
Research Costs	**6**	5	**15**	30
(Gain) Loss on Divestiture of Assets	**(1)**	5	**-**	6
Other (Income) Loss, Net	**(2)**	5	**(4)**	7
	(114)	201	**(2,786)**	177

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in the third quarter of 2017 were workforce costs, long-term incentives and office rent. General and administrative expenses increased by $45 million in the third quarter of 2017 compared with 2016 primarily due to $18 million of costs related to the transitional services provided by ConocoPhillips, a $12 million increase in long-term employee incentives costs related to an increase in our share price, and a $10 million increase in workforce costs primarily due to the Acquisition.

On a year-to-date basis, primary drivers of our general and administrative expenses were workforce costs and office rent. In 2017, general and administrative expenses decreased by $8 million compared with 2016 due to:

- Lower long-term employee incentive costs related to a drop in our share price;
- A non-cash expense of $7 million for certain Calgary office space in excess of Cenovus's current and near-term requirements, compared with $31 million in 2016; and
- Lower information technology costs due to process improvements.

These decreases were partially offset by approximately $28 million of transitional services provided by ConocoPhillips. Under the purchase and sales agreement, Cenovus and ConocoPhillips agreed to certain transitional services where ConocoPhillips will provide certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions are in the normal course of operations and are measured at the exchange amounts.

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. In the third quarter and on a year-to-date basis, finance costs increased by $94 million and $166 million, respectively, primarily due to costs associated with additional debt incurred to finance the Acquisition, including US$2.9 billion of senior unsecured notes, $3.6 billion borrowed under a committed Bridge Facility and borrowings through our existing committed credit facility. The first tranche and a portion of the second tranche of the committed Bridge Facility were repaid on September 29, 2017 with proceeds from the sale of our Pelican Lake assets and the adjacent Grand Rapids project. As at September 30, 2017, $2.65 billion remains outstanding on the committed Bridge Facility. As at September 30, 2017, no amounts were drawn on the existing committed credit facility.

The weighted average interest rate on outstanding debt for the three and nine months ended September 30, 2017 was 4.7 percent and 4.9 percent, respectively (2016 – 5.3 percent).

Foreign Exchange

	Three Months Ended September 30,		Nine Months Ended September 30,	
($ millions)	**2017**	2016	**2017**	2016
Unrealized Foreign Exchange (Gain) Loss	**(440)**	50	**(908)**	(341)
Realized Foreign Exchange (Gain) Loss	**90**	(5)	**72**	3
	(350)	45	**(836)**	(338)

In the third quarter and on a year-to-date basis in 2017, unrealized foreign exchange gains resulted primarily from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar at September 30, 2017, strengthened by four percent and eight percent respectively, in comparison to June 30, 2017 and December 31, 2016. On a year-to-date basis, unrealized foreign exchange gains also resulted from the translation of U.S. cash that was accumulated leading up to the Acquisition.

In the third quarter and on a year-to-date basis in 2017, realized foreign exchange losses primarily resulted from an increase in the number of sales contracts denominated in U.S. dollars.

Revaluation Gain

Prior to the Acquisition, our 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, "*Joint Arrangements*" and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, we control FCCL, as defined under IFRS 10, "*Consolidated Financial Statements*" and accordingly, FCCL has been consolidated. As required by IFRS 3 when control is achieved in stages, the previously held interest in FCCL was re-measured to its fair value of $12.3 billion and a non-cash revaluation gain of $2.5 billion ($1.8 billion, after-tax) was recorded in net earnings in the second quarter of 2017.

Transaction Costs

On a year-to-date basis in 2017, we expensed $56 million of transaction costs related to the Acquisition.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date of the Acquisition for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

The contingent payment is accounted for as a financial option. The fair value of $361 million on May 17, 2017 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is subsequently re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. At September 30, 2017, the contingent payment was valued at $252 million. In the three and nine months ended September 30, 2017, there was a re-measurement gain of $43 million and $109 million, respectively. WCS in the third quarter of 2017 averaged less than $52 per barrel, therefore no amount was payable.

Average WCS forward pricing for the remaining term of the contingent payment is US$35.51 or C$44.28 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$42.50 per barrel and C$48.60 per barrel.

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 $15 million (2016 – $14 million) and $47 million on a year-to-date basis (2016 – $50 million).

Income Tax

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Current Tax				
Canada	**(23)**	(71)	**(232)**	(187)
United States	**(39)**	-	**(40)**	1
Total Current Tax Expense (Recovery)	**(62)**	(71)	**(272)**	(186)
Deferred Tax Expense (Recovery)	**(48)**	5	**893**	(91)
Tax Expense (Recovery) From Continuing Operations	**(110)**	(66)	**621**	(277)

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

($ millions)	Nine Months Ended September 30, 2017	2016
Earnings (Loss) From Continuing Operations Before Income Tax	**3,701**	(527)
Canadian Statutory Rate	**27.0%**	27.0%
Expected Income Tax (Recovery)	**999**	(142)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(31)**	(38)
Non-Taxable Capital (Gains) Losses	**(148)**	(46)
Non-Recognition of Capital (Gains) Losses	**(121)**	(46)
Adjustments Arising From Prior Year Tax Filings	**(36)**	(48)
Recognition of Previously Unrecognized Capital Losses	**(65)**	-
Non-Deductible Expenses	**3**	6
Other	**20**	37
Total Expense (Recovery) From Continuing Operations	**621**	(277)
Effective Tax Rate	**16.8%**	52.6%

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, 2017, a current tax recovery was recorded on continuing operations due to the carry back of current and prior year losses and an adjustment related to prior years. In the third quarter, we recorded a deferred tax recovery as compared to an expense in 2016 on continuing operations. On a year-to-date basis, a deferred tax expense was recorded in 2017 compared with a recovery in 2016 on continuing operations due to the revaluation gain of our pre-existing interest in connection with the Acquisition.

In the three and nine months ended September 30, 2017, we recorded an income tax expense of $31 million and $51 million, respectively, related to discontinued operations (2016 – $89 million and $176 million income tax recovery, respectively). The loss on discontinuance includes a $163 million deferred tax recovery.

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 foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences. Our effective tax rate differs from the statutory tax rate due to $715 million of unrealized non-taxable foreign exchange gains.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Cash From (Used In)				
Operating Activities	**592**	310	**2,159**	697
Investing Activities	**512**	(196)	**(14,653)**	(835)
Net Cash Provided (Used) Before Financing Activities	**1,104**	114	**(12,494)**	(138)
Financing Activities	**(1,009)**	(41)	**9,227**	(125)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**48**	(3)	**179**	8
Increase (Decrease) in Cash and Cash Equivalents	**143**	70	**(3,088)**	(255)

	September 30, 2017	December 31, 2016
Cash and Cash Equivalents	**632**	3,720
Committed and Undrawn Credit Facilities	**4,500**	4,000

Cash From (Used In) Operating Activities

Cash from operating activities increased for the three and nine months ended September 30, 2017 mainly due to higher Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, assets and liabilities held for sale and the current portion of the contingent payment we had working capital of $1,302 million at September 30, 2017 compared with $4,423 million at December 31, 2016. The decrease in working capital was primarily due to the Acquisition.

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

Cash From (Used In) Investing Activities

In the third quarter of 2017, cash from investing activities was primarily due to cash proceeds from the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project, partially offset by an increase in capital investment. In 2016, capital investment was limited due to spending reductions in response to the low commodity price environment.

On a year-to-date basis, the increase in cash used in investing activities was primarily due to the Acquisition and a rise in capital investment, partially offset by proceeds on the divestiture of our Pelican Lake assets and the adjacent Grand Rapids project. In 2016, capital investment was limited due to spending reductions in response to the low commodity price environment.

Cash From (Used In) Financing Activities

Cash used in financing activities increased in the third quarter of 2017 primarily related to the repayment of the first tranche and a portion of the second tranche of the committed Bridge Facility. On a year-to-date basis, the increase in cash from financing activities was primarily due to the issuance of debt and common shares to help finance the Acquisition, partially offset by the repayment of a portion of the committed Bridge Facility.

Total debt as at September 30, 2017 was $12,094 million (December 31, 2016 – $6,332 million), which includes $9,547 million of U.S. denominated senior unsecured notes with no principal payments due until October 15, 2019 (US$1.3 billion) and $2.65 billion under a committed Bridge Facility, both amounts are partially offset by debt discount and transaction costs. The $5,762 million increase in total debt is primarily due to Acquisition financing.

As at September 30, 2017, we were in compliance with all of the terms of our debt agreements.

Senior Unsecured Notes

In connection with the Acquisition, on April 7, 2017, we completed an offering in the U.S. for US$2.9 billion of senior unsecured notes issued in three tranches, US$1.2 billion 4.25 percent senior unsecured notes due April 2027, US$700 million 5.25 percent senior unsecured notes due June 2037, and US$1.0 billion 5.40 percent senior unsecured notes due June 2047 (collectively, the "2017 Notes"). In connection with the offering of the 2017 Notes, we agreed to make an exchange offer (the "Exchange Offering") for the 2017 Notes whereby the holders will be entitled to exchange the 2017 Notes for new notes with the same terms and provisions, except that the new notes will not be subject to transfer restrictions.

Base Shelf Prospectus

On October 10, 2017, we filed a base shelf prospectus that allows us to offer, from time to time, up to US$7.5 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 also allows us to conduct the Exchange Offering and ConocoPhillips to offer, should they so choose from time to time, the common shares they acquired in connection with the Acquisition. The base shelf prospectus will expire in November 2019 and replaces our US$5.0 billion base shelf prospectus, which would have expired in March 2018. Offerings under the base shelf prospectus are subject to market conditions.

Committed Bridge Facility

On May 17, 2017, concurrent with the close of the Acquisition, we borrowed $3.6 billion under a committed Bridge Facility. The Bridge Facility consisted of a $0.9 billion tranche maturing on May 17, 2018, a $1.8 billion tranche maturing on November 17, 2018, and a $0.9 billion tranche maturing on May 17, 2019. On September 29, 2017, the first tranche and a portion of the second tranche were repaid resulting in $2.65 billion outstanding as at September 30, 2017. We expect to repay the remainder of the committed Bridge Facility with proceeds from the announced divestitures and further planned divestitures.

Common Shares

In connection with the Acquisition, on April 6, 2017, Cenovus closed a Bought-Deal Common Share Offering for 187.5 million common shares for gross proceeds of $3.0 billion.

Dividends

In the three and nine months ended September 30, 2017, we paid dividends of $0.05 per share or $62 million and $0.15 per share or $164 million, respectively (2016 – $0.05 per share or $41 million and $0.15 per share or $124 million, respectively). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

We expect cash flows from our liquids, 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. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, DBRS Limited, and Fitch Ratings.

The following sources of liquidity are available at September 30, 2017:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**632**
Committed Credit Facility – Tranche A	**November 2021**	**3,300**
Committed Credit Facility – Tranche B	**November 2020**	**1,200**

Committed Credit Facility

On April 28, 2017, we amended our existing committed credit facility to increase the capacity of the facility by $0.5 billion to $4.5 billion and to extend the maturity dates. The committed credit facility consists of a $1.2 billion tranche maturing on November 30, 2020 and $3.3 billion tranche maturing on November 30, 2021. As of September 30, 2017, we had $4.5 billion available under our committed credit facility.

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.

See below for the Debt to Capitalization ratio used by Cenovus to monitor our capital structure.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial measures 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 net earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, loss from discontinuance, and other income (loss), net, calculated on a trailing 12-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

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 times to 2.0 times. At different points within the economic cycle, we expect these ratios may periodically be outside of the target range.

As at	September 30, 2017	December 31, 2016
Net Debt to Capitalization [(1)] [(2)]	**37%**	18%
Debt to Capitalization	**38%**	35%
Net Debt to Adjusted EBITDA [(1)]	**4.1x**	1.9x
Debt to Adjusted EBITDA	**4.3x**	4.5x

(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.

Debt to Capitalization increased as a result of the higher long-term debt balance, related to the Acquisition, partially offset by the increase in Shareholders' Equity and the strengthening of the Canadian dollar relative to the U.S. dollar. Debt to Adjusted EBITDA decreased as a result of a higher Adjusted EBITDA from an increase in commodity prices and the rise in sales volumes as a result of the Acquisition, partially offset by a higher long-term debt balance. We are intently focused on completing divestitures of our legacy Conventional assets in order to deleverage our balance sheet.

As at September 30, 2017, Cenovus's Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA are 4.3x and 4.1x, respectively. These ratios are well outside our target range. However, it is important to note that Adjusted EBITDA is calculated on a rolling twelve month basis and as such, only includes the financial results from the Deep Basin Assets and the additional 50 percent of FCCL for the period May 17, 2017 to September 30, 2017. Debt and Net Debt are as at September 30, 2017; therefore, the ratios are fully burdened by the debt issued to finance the Acquisition. If Adjusted EBITDA reflected a full twelve months of earnings from the acquired assets, Cenovus's Debt and Net Debt to Adjusted EBITDA ratios would be substantially lower.

Additional information regarding our financial measures and capital structure can be found in the notes to the December 31, 2016 Consolidated Financial Statements and the interim Consolidated Financial Statements.

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 a Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Certain directors, officers or employees chose prior to December 31, 2016 to convert a portion of their remuneration, paid in the first quarter of 2017, into DSUs. The election for any particular year is irrevocable. DSUs may not be redeemed until departure. Directors also received an annual grant of DSUs.

Refer to Note 21 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, 2017	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**42,864**	**36,326**
Other Stock-Based Compensation Plans	**15,537**	**1,633**

In connection with the Acquisition, Cenovus closed a Bought-Deal Common Share financing on April 6, 2017 for 187.5 million common shares, raising gross proceeds of $3.0 billion ($2.9 billion net of $101 million of share issuance costs).

In addition, we issued 208 million common shares to ConocoPhillips on May 17, 2017 as partial consideration for the Acquisition. In relation to the share consideration, Cenovus and ConocoPhillips entered into an investor agreement, and a registration rights agreement which, among other things, restricts ConocoPhillips from selling or hedging its Cenovus common shares until November 17, 2017. ConocoPhillips is also restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the outstanding common shares of Cenovus.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services that were entered into in the normal course of business. Obligations are primarily related to demand charges on firm transportation agreements, operating leases on buildings, our risk management program and an obligation to fund our defined benefit pension and other post-employment benefit plans. Obligations that have original maturities of less than one year are excluded. For further information, see the notes to the December 31, 2016 Consolidated Financial Statements.

As at September 30, 2017, total commitments were $20.7 billion, of which $17.2 billion were for various transportation commitments. During the nine months ended September 30, 2017, our transportation commitments decreased by $9.1 billion, primarily due to our withdrawal from certain transportation initiatives, including the cancellation of the Energy East Pipeline, and use of contracts, partially offset by new firm transportation agreements. In relation to the Acquisition, we assumed $3.7 billion primarily consisting of transportation commitments on various pipelines. Transportation commitments include $7.5 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2016 – $19.2 billion). Terms are 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, 2017, there were outstanding letters of credit aggregating $257 million issued as security for performance under certain contracts (December 31, 2016 – $258 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our interim Consolidated Financial Statements.

Contingent Payment

In connection with the Acquisition and related to oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at September 30, 2017, the estimated fair value of the contingent payment was $252 million. WCS in the third quarter of 2017 averaged less than $52 per barrel; therefore, no amount was payable. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management section of our 2016 annual MD&A and the first and second quarter 2017 MD&A. In addition, a description of the risk factors and uncertainties 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, 2016.

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 2016 annual MD&A, the first and second quarter 2017 MD&A and our AIF.

The following provides an update on our risks related to commodity prices, risks related to the Acquisition, and risks related to asset divestitures.

Commodity Price Risk

Fluctuations in commodity prices and refined product prices impact 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 23 and 24 to the interim Consolidated Financial Statements.

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 if commodity prices increase. These risks are minimized through hedging limits that are reviewed annually by the Board, as required by our Market Risk Mitigation Policy.

Impact of Financial Risk Management Activities

($ millions)	Three Months Ended September 30, 2017 Realized	Unrealized	Total	2016 Realized	Unrealized	Total
Crude Oil	**9**	**483**	**492**	(32)	(5)	(37)
Refining	**-**	**2**	**2**	1	-	1
Power	**-**	**-**	**-**	(3)	-	(3)
Interest Rate	**-**	**1**	**1**	-	12	12
Foreign Exchange	**1**	**-**	**1**	-	-	-
(Gain) Loss on Risk Management (1)	**10**	**486**	**496**	(34)	7	(27)
Income Tax Expense (Recovery)	**(18)**	**(132)**	**(150)**	9	(2)	7
(Gain) Loss on Risk Management, After Tax	**(8)**	**354**	**346**	(25)	5	(20)

(1) *Excludes $3 million of realized risk management losses on contracts from our Conventional segment (2016 – $7 million realized risk management gains), which has been classified as a discontinued operation.*

($ millions)	Nine Months Ended September 30, 2017 Realized	Unrealized	Total	2016 Realized	Unrealized	Total
Crude Oil	**72**	**66**	**138**	(138)	359	221
Refining	**4**	**(1)**	**3**	(4)	4	-
Power	**-**	**-**	**-**	-	(14)	(14)
Interest Rate	**-**	**10**	**10**	-	91	91
Foreign Exchange	**(142)**	**-**	**(142)**	-	-	-
(Gain) Loss on Risk Management (2)	**(66)**	**75**	**9**	(142)	440	298
Income Tax Expense (Recovery)	**-**	**(20)**	**(20)**	37	(120)	(83)
(Gain) Loss on Risk Management, After Tax	**(66)**	**55**	**(11)**	(105)	320	215

(2) *Excludes $19 million of realized risk management losses on contracts from our Conventional segment (2016 – $57 million realized risk management gains), which has been classified as a discontinued operation.*

In the third quarter of 2017 and on a year-to-date basis, we incurred realized losses on crude oil risk management activities, consistent with average benchmark prices exceeding our contract prices. On a year-to-date basis, we incurred realized gains on foreign exchange contracts undertaken to support the Acquisition. Unrealized losses were recorded on our crude oil financial instruments in the three and nine months ended September 30, 2017 primarily due to the realization of settled positions and changes in benchmark prices.

Risks Related to the Acquisition and Asset Divestitures

Unexpected Costs or Liabilities Related to the Acquisition

Acquisitions of crude oil and natural gas properties are based largely on engineering, environmental and economic assessments made by the acquiror, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of crude oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of crude oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic, engineering, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Although we conducted title and environmental reviews in respect of the Deep Basin Assets, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat our title to certain assets or that environmental defects or deficiencies do not exist.

In connection with the Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence conducted prior to the execution of the Acquisition Agreement and we may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities could have a material adverse effect on our business, financial condition or future prospects. In addition, the Acquisition Agreement limits the amount for which we are indemnified, such that liabilities in respect of the Acquisition may be greater than the amounts for which we are indemnified under the Acquisition Agreement.

Realization of Acquisition Benefits

We believe that the Acquisition will provide a number of benefits to Cenovus. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, may cost more to achieve or may not occur within the time periods that we anticipate. The realization of such benefits may be affected by a number of factors, many of which are beyond our control.

Amount of Contingent Payments

In connection with the Acquisition, we have agreed to make contingent payments under certain circumstances. The amount of contingent payments will vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Acquisition, and such payments may be significant. In addition, in the event that such payments are made, this could have an adverse impact on our reported results and other metrics.

Significant Transaction and Related Costs

We expect to incur a number of costs associated with completing the Acquisition, integrating the Deep Basin Assets and completing the targeted asset sales. The majority of such costs will consist of acquisition, facilities and systems consolidation and employment-related costs. Additional unanticipated costs may be incurred in the integration of the assets to be acquired under the Acquisition (collectively, the "Acquired Assets") into our business and completing the targeted asset sales.

Operational and Reserves and Resources Risks Relating to the Acquired Assets

The risk factors set forth in our AIF relating to the crude oil and natural gas business, environmental matters and the operations and reserves and resources of Cenovus apply equally in respect of the Acquired Assets. In particular, the reserves, resources and recovery information contained in the reserves and resources reports in respect of the Acquired Assets is only an estimate and the actual production from and ultimate reserves of those properties may be greater or less than the estimates contained in such reports.

Risk of Default in the Repayment of Borrowings under the Credit Facilities

We have incurred material indebtedness under our committed Bridge Facility. We intend to repay borrowings under the committed Bridge Facility through the sale of certain of our assets. We may not be able to sell such assets in the time period we estimate, or for prices we expect to realize from such sales. If we are unable to sell such assets on the terms that we expect to receive, or at all, our ability to repay borrowings under the committed Bridge Facility as anticipated could be adversely affected. In the event we are unable to refinance borrowings we incur under our committed Bridge Facility in the manner intended, we may be required to utilize other sources of liquidity including cash on hand, cash from operating activities or borrowings under our existing committed credit facility to the extent of any availability thereunder. We may also be required to seek extensions to or modifications of the terms of our existing committed credit facility or committed Bridge Facility in order to defer the maturity dates of borrowings incurred thereunder. In recent years, depressed prices for crude oil and natural gas have materially affected the operating and financial performance of borrowers in the energy sector which has at times resulted in the curtailment of the availability of credit from lenders, and an unwillingness to provide borrowers with desired extensions to, or other modifications of, repayment terms. As a result, depending on crude oil and natural gas and credit market conditions at the time when borrowings under our existing committed credit facility or committed Bridge Facility are due for repayment, and our own financial performance at that time, we may be unable to obtain extensions or modifications of the terms of our existing committed credit facility or committed Bridge Facility on terms satisfactory to us, or at all, which could result in us defaulting on our repayment obligations under our existing committed credit facility or committed Bridge Facility and being subject to various remedies available to the lenders thereunder including remedies available under applicable bankruptcy and insolvency legislation.

Increased Indebtedness

In order to finance the Acquisition, we borrowed $3.6 billion on a committed Bridge Facility and issued US$2.9 billion in senior unsecured notes. Such borrowings represent a significant increase in Cenovus's consolidated indebtedness. Such additional indebtedness increased Cenovus's interest expense and debt service obligations and may have a negative effect on Cenovus's results of operations. On September 29, 2017, we completed the sale of our Pelican Lake assets and the adjacent Grand Rapids project, the first of a series of anticipated divestitures, for gross cash proceeds of $975 million. Net cash proceeds from the sale were applied against the $3.6 billion committed Bridge Facility. As at September 30, 2017, we had $2.65 billion outstanding on the committed Bridge Facility. On September 25, 2017, we announced the sale of our Suffield assets for gross cash proceeds of $512 million, plus a DPPA. In addition, on October 19, 2017, we announced the sale of our Palliser assets for gross cash proceeds of $1.3 billion. Both transactions are expected to close in the fourth quarter of 2017, subject to customary closing conditions. Net proceeds from the divestitures will be applied against the committed Bridge Facility.

Cenovus's ability to service its increased debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions, interest rate fluctuations and financial, business, regulatory and other factors, some of which are beyond Cenovus's control. If Cenovus's operating results are not sufficient to service its current or future indebtedness, Cenovus may be forced to take actions such as reducing dividends, reducing or delaying business activities, investments or capital expenditures, selling assets, restructuring or refinancing its debt, or seeking additional equity capital.

Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. The increased indebtedness of Cenovus arising from the Acquisition could be a factor considered by the ratings agencies in downgrading Cenovus's credit rating. If a rating agency were to downgrade Cenovus's credit rating, Cenovus's borrowing costs could increase and its funding sources could decrease. In addition, a failure by Cenovus to maintain its current credit ratings could affect its business relationships with suppliers and operating partners. A credit downgrade could also adversely affect the availability and cost of capital needed to fund the growth investments that are a central element to Cenovus's long-term business strategy.

Suffield and Palliser Divestitures

We have announced the divestiture of our Suffield and Palliser assets, which are expected to close in the fourth quarter. Both divestitures are subject to required regulatory approvals and the satisfaction of certain closing conditions. There is no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when they will be satisfied. If they are not satisfied or waived, the divestitures will not be completed. In addition, a substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms or conditions in the approvals could have a material adverse effect on our ability to complete the divestitures and on our business, financial condition, results of operations or cash flows following the divestitures. If the divestitures are not completed as contemplated, we could suffer adverse consequences, including the loss of investor confidence.

British Columbia Exposure

Pursuant to the Acquisition, we acquired approximately 0.9 million gross acres (0.7 million net acres) of land holdings in British Columbia, which exposes us to the following additional risks.

Aboriginal Claims

Aboriginal groups have claimed aboriginal title and rights to portions of Western Canada, including British Columbia, and such claims, if successful, could have a material negative impact on Cenovus. The Governments of Canada and British Columbia have a duty to consult with Aboriginal people in relation to actions and decisions which may impact those rights and claims and, in certain cases, have a duty to accommodate their concerns. These duties have the potential to adversely affect Cenovus's ability to obtain and renew permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. The scope of the duty to consult by the federal Government of Canada and the Government of British Columbia is subject to ongoing litigation which may result in uncertainty with respect to the process to obtain permits, leases, licenses and other approvals. Opposition by Aboriginal groups may also negatively impact Cenovus in terms of public perception, diversion of Management's time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in Cenovus's operations, or court-ordered relief impacting Cenovus's operations. Challenges by Aboriginal groups could adversely impact Cenovus's progress and ability to explore and develop its properties.

Climate Change Regulation

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80 percent reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia has committed to implementing a formal policy to regulate carbon capture and storage projects.

Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45 percent reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that will involve a new offset protocol and a Clean Infrastructure Royalty Credit Program, and finally a Future phase that will include the development and implementation of new methane emissions reduction standards.

Environmental Regulation

In British Columbia, the Oil and Gas Activities Act (the "OGAA") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The Environmental Protection and Management Regulation establishes the government's environmental objectives for Crown lands for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not exclusively an environmental statute, the Petroleum and Natural Gas Act, in conjunction with the OGAA, requires companies to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Royalty Regime

Producers of crude oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, and make monthly royalty payments in respect of crude oil and natural gas produced. The amount payable as a royalty in respect of crude oil depends on the type and vintage of the crude oil, the quantity of crude oil produced in a month and the value of that crude oil. Generally, crude oil is classified as either light or heavy and the vintage of crude oil is classified as either: "old oil" that is produced from a pool with a completed well that first recovered crude oil before October 31, 1975; "new oil" that is produced from a pool with a completed well that first recovered oil between October 31, 1975 and June 1, 1998; or "third-tier oil" that is produced from a pool with a completed well that first recovered crude oil after June 1, 1998 or through an enhanced oil recovery scheme. The royalty calculation takes into account the production of crude oil on a well-by-well basis, the specified royalty rate for a given vintage of crude oil, the average unit-selling price of the crude oil and any applicable royalty exemptions. Royalty rates are reduced on low-productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with crude oil), the royalty rate depends on the date of acquisition of the crude oil and natural gas tenure rights and the spud date of the well, and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on NGLs are levied at a flat rate of 20 percent of sales volume.

Producers of crude oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For crude oil, the applicable freehold production tax is based on the volume of monthly production, and is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the applicable freehold production tax is a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold NGLs is a flat rate of 12.25 percent. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale between $1.25 – $4.94 per hectare, depending on the total number of hectares owned by the entity.

The Government of British Columbia maintains a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity natural gas wells. These include both royalty credit and royalty reduction programs.

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50 percent of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased crude oil and natural gas exploration and production in under-developed areas and to extend the drilling season.

Any future changes by the Government of British Columbia to the royalty programs or regimes could have a significant impact on Cenovus's financial condition, results of operations and future capital expenditures.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES 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 annual December 31, 2016 Consolidated Financial Statements and the interim Consolidated Financial Statements for the period ended September 30, 2017.

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, 2017. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2016.

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. Further to those areas discussed in the annual Consolidated Financial Statements for the year ended December 31, 2016 and the annual MD&A, the estimation of fair values of the assets acquired and liabilities assumed in a business combination, including the contingent payment and goodwill, is a key area involving significant estimates or judgments.

Recent Accounting Pronouncements

There were no new or amended accounting standards or interpretations adopted during the nine months ended September 30, 2017.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning after January 1, 2017 and have not been applied in preparing the interim Consolidated Financial Statements. The following provides an update to the disclosure in the annual Consolidated Financial Statements for the year ended December 31, 2016.

Revenue Recognition

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

IFRS 15 is effective for annual periods beginning on or after January 1, 2018. The standard may be applied retrospectively or using the retrospective with cumulative effect approach. We are currently evaluating the impact of adopting IFRS 15 on the Consolidated Financial Statements and plan to adopt the standard for the year ended December 31, 2018.

Leases

On January 13, 2016, the IASB issued IFRS 16, "*Leases*" ("IFRS 16"), which requires entities to recognize lease assets and lease obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements, and may continue to be treated as operating leases.

Lessors will continue with a dual lease classification model. Classification will determine how and when a lessor will recognize lease revenue, and what assets would be recorded.

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively.

We plan to apply IFRS 16 on January 1, 2019. A transition team is assessing the impacts of adopting IFRS 16 and will oversee changes to accounting systems, processes and internal controls. The estimated time and effort necessary to develop and implement required changes (including the impact to information technology systems) extends into 2018. Although the transition approach on adoption has not yet been determined, it is anticipated that the adoption of IFRS 16 will have a material impact on the Consolidated Balance Sheets.

CONTROL ENVIRONMENT

Except for changes relating to the continuing integration of the Deep Basin Assets, as discussed below, there have been no changes to internal control over financial reporting ("ICFR") or disclosure controls and procedures ("DC&P") during the three months ended September 30, 2017 that have materially affected, or are reasonably likely to materially affect, ICFR or DC&P.

As permitted by and in accordance with, National Instrument 52-109, "*Certification of Disclosure in Issuers' Annual and Interim Filings*", Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures of the Deep Basin Assets that were acquired on May 17, 2017 (see the Financing the Acquisition section of this MD&A for more details). Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to the Deep Basin Assets in a manner consistent with our other operations. Summary financial information related to the Deep Basin Assets included in the interim Consolidated Financial Statements is as follows:

($ millions)	Three Months Ended September 30, 2017
Revenues	**187**
Operating Margin [(1)]	**64**
Net Earnings (Loss)	**(27)**
As at	**September 30, 2017**
Current Assets	**130**
Non-Current Assets [(1)]	**6,570**
Current Liabilities	**115**
Non-Current Liabilities [(1)]	**621**

(1) *Summary financial information included within net earnings (loss), non-current assets, and non-current liabilities includes both information obtained from predecessor accounting systems prior to full conversion to Cenovus systems, as well as financial information that is included in our accounting systems, such as, property, plant and equipment , exploration and evaluation assets, decommissioning liabilities, and long-term incentive costs.*

In addition, we acquired approximately $500 million of Deep Basin commitments primarily consisting of transportation commitments on various pipelines.

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 expect 2017 to be a transformational year for Cenovus. The close of the Acquisition in the second quarter of 2017 increased our interest in FCCL to 100 percent and provided us with a second core operating area in the Deep Basin. As part of our ongoing efforts to optimize our asset portfolio and focus on deleveraging our balance sheet, we announced our intention to sell our legacy Conventional crude oil and natural gas assets in the first half of 2017. In the third quarter, we successfully completed the sale of our Pelican Lake assets and the adjacent Grand Rapids project, and announced the sale of our Suffield assets. Furthermore, on October 19, 2017, we announced the divestiture of our Palliser assets. Both transactions are expected to close in the fourth quarter of 2017. The divestiture process for our remaining legacy Conventional assets, notably our CO_2 enhanced oil recovery project at Weyburn, in southern Saskatchewan, is proceeding well.

We believe we are well-positioned for continued market and commodity price volatility. We will continue to look for ways to increase our margins through strong operating performance and cost leadership, while delivering safe and reliable operations. Proactively managing our market access commitments and opportunities should assist with our goal of reaching a broader customer base to secure a higher sales price for our liquids production.

We have reduced the amount of capital needed to sustain our base business and expand our projects, which we expect will allow us to reactivate growth in a disciplined manner. We believe these efforts will help to ensure our financial resilience.

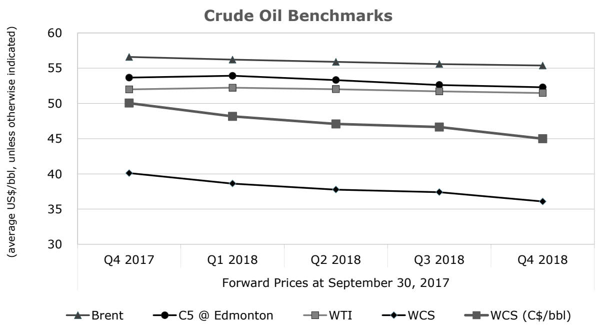
The following outlook commentary is focused on the next twelve to fifteen months.

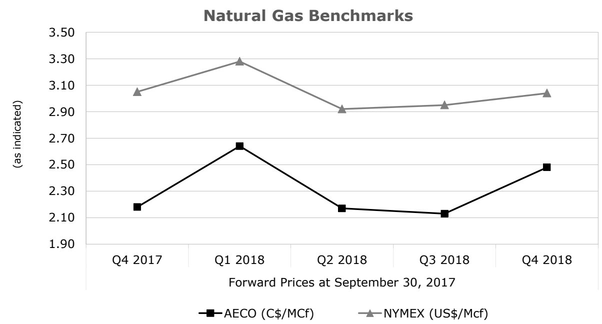
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility to continue and a modest price improvement in the next fifteen months. OPEC's ability to adhere to its current production cuts and the possibility of future production cuts, combined with annual increases in demand growth should support prices, constrained by the need to draw down surplus crude oil inventories and U.S. production growth;
- We anticipate the Brent-WTI differential will narrow after the impacts of severe weather related incidents dissipate and as a result of the U.S. 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 Canadian supply increasing due to the resolution of production outages, oil sands supply growth and potential transportation constraints, partially offset by the possibility of OPEC extending production cuts.

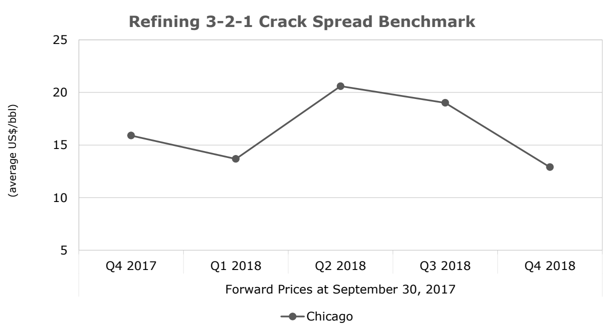


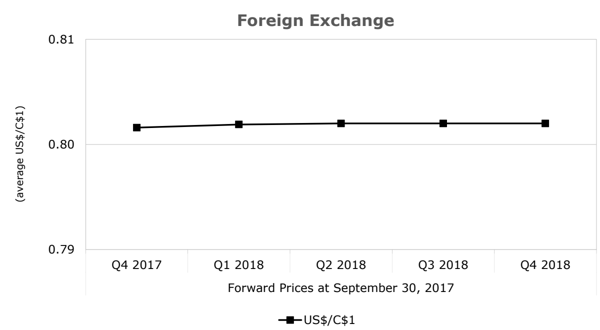


Natural gas prices are anticipated to improve in the fourth quarter of 2017 and first quarter of 2018 with a normal winter heating season and increased U.S. natural gas exports, partially offset by expected North American natural gas supply growth. In addition, recent pipeline and compressor station maintenance within Alberta will increase exports out of western Canada, helping to improve AECO prices.

U.S. refining crack spreads are expected to weaken in the fourth quarter of 2017 as refinery capacity returns after severe weather events and due to seasonal demand weakness. Seasonal demand changes will result in fluctuations of refining cracks spreads throughout the remainder of 2018. The impact of weaker refining crack spreads on refinery margins will be partially offset by the widening of the WTI-WCS differential, which increases the refinery feedstock cost advantage.

We expect the Canadian dollar to continue to be tied to a modest improvement in crude oil prices and the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise benchmark lending rates. The Bank of Canada has raised its benchmark lending rate twice this year marking a notable shift for Canada towards a tighter monetary policy.





Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially 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.

Additional natural gas and NGLs production associated with the Acquisition will provide improved upstream integration for the fuel, solvent and blending requirements at our oil sands operations.

Key Priorities for the Remainder of 2017

Maintain Financial Resilience and Executional Excellence

We remain focused on maintaining our financial resilience and flexibility while continuing to deliver safe operations, which remains a top priority. Reducing our debt position is our number one priority. Our plans to divest our legacy Conventional assets are progressing and are on track. We are targeting between $4.0 billion and $5.0 billion, gross, in announced asset sale agreements by the end of 2017, the proceeds of which will be used to retire the committed Bridge Facility and deleverage our balance sheet.

At September 30, 2017, through a combination of cash and our committed credit facility, we have approximately $5.1 billion of liquidity. We believe our liquidity position and the downside protection from our commodity hedging program should provide us the financial flexibility and resilience to maximize the value we realize on our asset sales and execute on our near-term deleveraging plan.

Disciplined and Value-Added Growth

In 2017, we anticipate capital investment to be between approximately $1.55 billion and $1.65 billion, a decline of six percent from our guidance dated July 26, 2017, as a result of ongoing cost savings, efficiency improvements, divestiture activities, and our continued focus on capital discipline.

We intend to focus on optimizing our capital investment and development plans in the oil sands and Deep Basin for a variety of commodity price environments. We will remain disciplined with a moderate pace of growth in the oil sands that continues to focus on controlling costs and capital efficiencies. We also anticipate a disciplined development approach to the Deep Basin Assets in 2017 and anticipate ramping up our activity levels through 2020. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

Cost and Margin Leadership

We remain committed to cost and margin leadership. We plan to continue to focus on reducing costs by leveraging our increased size and scale as well as through the advancement of technologies and enhancing our base business. We believe there is an opportunity for operating cost reductions in the Deep Basin as we fully integrate these assets. Our ability to drive structural and sustainable cost and margin improvements will further support our business plan and financial resilience.

Market Access

Market access constraints for Canadian crude oil continue to be a challenge. Our strategy is to maintain firm transportation commitments through a combination of pipelines, rail and marine access to support our growth plans, but leave capacity for optimization. We expect to supplement firm capacity with active blending, storage, sourcing and destination optimization to ensure we are maximizing the margin on every barrel we produce.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2016 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, 2017 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, 2016 and our Statement of Contingent and Prospective Resources.

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

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the United States Private Securities Litigation Reform Act of 1995, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as “anticipate”, “believe”, “expect”, “estimate”, “plan”, “forecast”, “future”, “target”, “position”, “project”, “committed”, “can be”, “pursue”, “capacity”, “could”, “should”, “will”, “focus”, “outlook”, “potential”, “priority”, “may”, “strategy”, “forward”, or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules, including expected timing for oil sands expansion phases and associated expected production capacities; projections for 2017 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; our future opportunities for oil development; forecast operating and financial results, including forecast sales prices, costs and cash flows; targets for our Debt to Capitalization and Debt to Adjusted EBITDA ratios; our ability to satisfy payment obligations as they become due; priorities for our capital investment decisions; planned capital expenditures, including the amount, 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 2017; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices and the Acquisition; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof by Cenovus, and anticipated impact on the Consolidated Balance Sheets; expected impacts of the Acquisition; the availability and repayment of our credit facilities; potential asset sales and anticipated use of sales proceeds; expected impacts of the contingent payment related to the Acquisition; future use and development of technology; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future cost reductions; and projected growth and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas prices and other assumptions inherent in Cenovus’s 2017 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our 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; achievement of expected impacts of the Acquisition; successful integration of the Deep Basin Assets; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and the timelines we expect; forecast crude oil and natural gas prices, forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized Western Canadian Select ("WCS") prices and WCS prices used to calculate the contingent payment to ConocoPhillips; our projected capital investment levels, the flexibility of capital spending plans and the associated sources of funding; sustainability of achieved cost reductions, achievement of further cost reductions and sustainability thereof; our ability to access and implement all technology necessary to achieve expected future results; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2017 guidance, as updated November 1, 2017, assumes: Brent prices of US$53.50/bbl, WTI prices of US$50.00/bbl; WCS of US$38.25/bbl; NYMEX natural gas prices of US$3.15/MMBtu; AECO natural gas prices of $2.40/GJ; Chicago 3-2-1 crack spread of US$15.50/bbl; and an exchange rate of $0.78 US$/C$.

Unless otherwise specifically stated or the context dictates otherwise, the financial outlook and forward looking metrics in this news release, in addition to the generally applicable assumptions described above, do not include or account for the effects or impacts of planned asset sales.

The risk factors and uncertainties that could cause our actual results to differ materially, include: possible failure by us to realize the anticipated benefits of and synergies from the Acquisition; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity 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; possible lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; 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 the operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Debt (and Net Debt) to Adjusted EBITDA as well as Debt (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, future production and future net revenue estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship 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 or maintain acceptance in the market; risks associated with 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; our ability to secure adequate and cost-effective product transportation including sufficient pipeline, crude-by-rail, marine or 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; possible failure to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change 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 general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; 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.

Statements relating to "reserves" and "resources" are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future.

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward looking information. 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, 2016, available on SEDAR at sedar.com, on 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
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
BOE	barrel of oil equivalent	Bcf	billion cubic feet
MMBOE	million barrel of oil equivalent	MMBtu	million British thermal units
WTI	West Texas Intermediate	GJ	gigajoule
WCS	Western Canadian Select	AECO	Alberta Energy Company
CDB	Christina Dilbit Blend	NYMEX	New York Mercantile Exchange
		TM	trademark of Cenovus Energy Inc.

NETBACK RECONCILIATIONS

The following tables provide a reconciliation of the items comprising Netbacks to Operating Margin found in our Interim Consolidated Financial Statements.

Total Production

Upstream Financial Results

Three Months Ended September 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements			
	Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	2,210	200	331	2,741
Less: Royalties	54	13	45	112
	2,156	187	286	2,629
Expenses				
Transportation and Blending	1,066	22	44	1,132
Operating	257	101	118	476
Production and Mineral Taxes	-	-	4	4
Netback	833	64	120	1,017
(Gain) Loss on Risk Management	9	-	3	12
Operating Margin	824	64	117	1,005

Three Months Ended September 30, 2016 ($ millions)	Per Interim Consolidated Financial Statements			
	Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	793	-	330	1,123
Less: Royalties	4	-	35	39
	789	-	295	1,084
Expenses				
Transportation and Blending	429	-	44	473
Operating	128	-	102	230
Production and Mineral Taxes	-	-	4	4
Netback	232	-	145	377
(Gain) Loss on Risk Management	(35)	-	(7)	(42)
Operating Margin	267	-	152	419

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Found in Note 8 of the interim Consolidated Financial Statements.

Netback Reconciliations

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation	Adjustments			Per Above Table
	Total	Condensate	Inventory	Other	Total Upstream
Revenues					
Gross Sales	1,836	885	-	20	2,741
Less: Royalties	114	-	-	(2)	112
	1,722	885	-	22	2,629
Expenses					
Transportation and Blending	248	885	(1)	-	1,132
Operating	469	-	-	7	476
Production and Mineral Taxes	4	-	-	-	4
Netback	1,001	-	1	15	1,017
(Gain) Loss on Risk Management	12	-	-	-	12
Operating Margin	989	-	1	15	1,005

Three Months Ended September 30, 2016 ($ millions)	Basis of Netback Calculation	Adjustments			Per Above Table
	Total	Condensate	Inventory	Other	Total Upstream
Revenues					
Gross Sales	762	358	-	3	1,123
Less: Royalties	39	-	-	-	39
	723	358	-	3	1,084
Expenses					
Transportation and Blending	115	358	-	-	473
Operating	227	-	-	3	230
Production and Mineral Taxes	4	-	-	-	4
Netback	377	-	-	-	377
(Gain) Loss on Risk Management	(41)	-	-	(1)	(42)
Operating Margin	418	-	-	1	419

Total Production

Upstream Financial Results

Nine Months Ended September 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	**4,938**	**324**	**1,091**	**6,353**
Less: Royalties	**117**	**21**	**145**	**283**
	4,821	**303**	**946**	**6,070**
Expenses				
Transportation and Blending	**2,511**	**32**	**149**	**2,692**
Operating	**618**	**152**	**343**	**1,113**
Production and Mineral Taxes	**-**	**-**	**14**	**14**
Netback	**1,692**	**119**	**440**	**2,251**
(Gain) Loss on Risk Management	**72**	**-**	**19**	**91**
Operating Margin	**1,620**	**119**	**421**	**2,160**

Nine Months Ended September 30, 2016 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	1,972	-	898	2,870
Less: Royalties	7	-	88	95
	1,965	-	810	2,775
Expenses				
Transportation and Blending	1,228	-	136	1,364
Operating	359	-	331	690
Production and Mineral Taxes	-	-	9	9
Netback	378	-	334	712
(Gain) Loss on Risk Management	(165)	-	(57)	(222)
Operating Margin	543	-	391	934

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Found in Note 8 of the interim Consolidated Financial Statements.

Netback Reconciliations

Nine Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation: Total	Adjustments: Condensate	Inventory	Other	Per Above Table: Total Upstream
Revenues					
Gross Sales	**4,172**	**2,147**	**-**	**34**	**6,353**
Less: Royalties	**284**	**-**	**-**	**(1)**	**283**
	3,888	**2,147**	**-**	**35**	**6,070**
Expenses					
Transportation and Blending	**543**	**2,147**	**-**	**2**	**2,692**
Operating	**1,098**	**-**	**-**	**15**	**1,113**
Production and Mineral Taxes	**14**	**-**	**-**	**-**	**14**
Netback	**2,233**	**-**	**-**	**18**	**2,251**
(Gain) Loss on Risk Management	**91**	**-**	**-**	**-**	**91**
Operating Margin	**2,142**	**-**	**-**	**18**	**2,160**

Nine Months Ended September 30, 2016 ($ millions)	Basis of Netback Calculation: Total	Adjustments: Condensate	Inventory	Other	Per Above Table: Total Upstream
Revenues					
Gross Sales	1,790	1,070	-	10	2,870
Less: Royalties	95	-	-	-	95
	1,695	1,070	-	10	2,775
Expenses					
Transportation and Blending	345	1,070	(51)	-	1,364
Operating	684	-	-	6	690
Production and Mineral Taxes	9	-	-	-	9
Netback	657	-	51	4	712
(Gain) Loss on Risk Management	(223)	-	-	1	(222)
Operating Margin	880	-	51	3	934

Oil Sands

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements [(1)]: Total Oil Sands
Revenues								
Gross Sales	603	737	1,340	1	863	-	6	2,210
Less: Royalties	43	11	54	-	-	-	-	54
	560	726	1,286	1	863	-	6	2,156
Expenses								
Transportation and Blending	126	79	205	-	863	(1)	(1)	1,066
Operating	138	116	254	1	-	-	2	257
Netback	296	531	827	-	-	1	5	833
(Gain) Loss on Risk Management	2	7	9	-	-	-	-	9
Operating Margin	294	524	818	-	-	1	5	824

Three Months Ended September 30, 2016 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements [(1)]: Total Oil Sands
Revenues								
Gross Sales	236	215	451	4	337	-	1	793
Less: Royalties	1	3	4	-	-	-	-	4
	235	212	447	4	337	-	1	789
Expenses								
Transportation and Blending	59	33	92	-	337	-	-	429
Operating	68	57	125	2	-	-	1	128
Netback	108	122	230	2	-	-	-	232
(Gain) Loss on Risk Management	(16)	(18)	(34)	-	-	-	(1)	(35)
Operating Margin	124	140	264	2	-	-	1	267

Nine Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements [(1)]: Total Oil Sands
Revenues								
Gross Sales	1,319	1,541	2,860	7	2,060	-	11	4,938
Less: Royalties	87	30	117	-	-	-	-	117
	1,232	1,511	2,743	7	2,060	-	11	4,821
Expenses								
Transportation and Blending	281	170	451	-	2,060	-	-	2,511
Operating	328	280	608	6	-	-	4	618
Netback	623	1,061	1,684	1	-	-	7	1,692
(Gain) Loss on Risk Management	33	39	72	-	-	-	-	72
Operating Margin	590	1,022	1,612	1	-	-	7	1,620

Nine Months Ended September 30, 2016 ($ millions)	Basis of Netback Calculation: Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements [(1)]: Total Oil Sands
Revenues								
Gross Sales	490	476	966	9	994	-	3	1,972
Less: Royalties	2	5	7	-	-	-	-	7
	488	471	959	9	994	-	3	1,965
Expenses								
Transportation and Blending	172	106	278	-	994	(44)	-	1,228
Operating	192	156	348	8	-	-	3	359
Netback	124	209	333	1	-	44	-	378
(Gain) Loss on Risk Management	(79)	(85)	(164)	-	-	-	(1)	(165)
Operating Margin	203	294	497	1	-	44	1	543

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Deep Basin

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements (1) Total Deep Basin
Revenues			
Gross Sales	187	13	200
Less: Royalties	13	-	13
	174	13	187
Expenses			
Transportation and Blending	20	2	22
Operating	96	5	101
Production and Mineral Taxes	-	-	-
Netback	58	6	64
(Gain) Loss on Risk Management	-	-	-
Operating Margin	58	6	64

Nine Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements (1) Total Deep Basin
Revenues			
Gross Sales	305	19	324
Less: Royalties	21	-	21
	284	19	303
Expenses			
Transportation and Blending	30	2	32
Operating	143	9	152
Production and Mineral Taxes	-	-	-
Netback	111	8	119
(Gain) Loss on Risk Management	-	-	-
Operating Margin	111	8	119

(1) Found in Note 1 of the interim Consolidated Financial Statements.

Conventional

	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements (1)
Three Months Ended September 30, 2017 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Revenues										
Gross Sales	111	131	4	246	62	308	22	-	1	331
Less: Royalties	17	26	1	44	3	47	-	-	(2)	45
	94	105	3	202	59	261	22	-	3	286
Expenses										
Transportation and Blending	13	7	-	20	3	23	22	-	(1)	44
Operating	35	44	-	79	39	118	-	-	-	118
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
Netback	46	50	3	99	17	116	-	-	4	120
(Gain) Loss on Risk Management	1	3	-	4	(1)	3	-	-	-	3
Operating Margin	45	47	3	95	18	113	-	-	4	117

	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements (1)
Three Months Ended September 30, 2016 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Revenues										
Gross Sales	104	114	3	221	86	307	21	-	2	330
Less: Royalties	10	21	1	32	3	35	-	-	-	35
	94	93	2	189	83	272	21	-	2	295
Expenses										
Transportation and Blending	13	6	-	19	4	23	21	-	-	44
Operating	32	33	-	65	35	100	-	-	2	102
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
Netback	49	50	2	101	44	145	-	-	-	145
(Gain) Loss on Risk Management	(5)	(2)	-	(7)	-	(7)	-	-	-	(7)
Operating Margin	54	52	2	108	44	152	-	-	-	152

(1) Found in Note 8 of the interim Consolidated Financial Statements.

Conventional

Nine Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Conventional
Revenues										
Gross Sales	**343**	**397**	**13**	**753**	**247**	**1,000**	**87**	**-**	**4**	**1,091**
Less: Royalties	**49**	**83**	**2**	**134**	**12**	**146**	**-**	**-**	**(1)**	**145**
	294	**314**	**11**	**619**	**235**	**854**	**87**	**-**	**5**	**946**
Expenses										
Transportation and Blending	**32**	**20**	**-**	**52**	**10**	**62**	**87**	**-**	**-**	**149**
Operating	**103**	**121**	**-**	**224**	**117**	**341**	**-**	**-**	**2**	**343**
Production and Mineral Taxes	**-**	**13**	**-**	**13**	**1**	**14**	**-**	**-**	**-**	**14**
Netback	**159**	**160**	**11**	**330**	**107**	**437**	**-**	**-**	**3**	**440**
(Gain) Loss on Risk Management	**10**	**10**	**-**	**20**	**(1)**	**19**	**-**	**-**	**-**	**19**
Operating Margin	**149**	**150**	**11**	**310**	**108**	**418**	**-**	**-**	**3**	**421**

Nine Months Ended September 30, 2016 ($ millions)	Basis of Netback Calculation: Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Adjustments: Condensate	Inventory	Other	Per Interim Consolidated Financial Statements (1): Total Conventional
Revenues										
Gross Sales	272	315	7	594	221	815	76	-	7	898
Less: Royalties	24	54	2	80	8	88	-	-	-	88
	248	261	5	514	213	727	76	-	7	810
Expenses										
Transportation and Blending	36	19	-	55	12	67	76	(7)	-	136
Operating	103	112	-	215	113	328	-	-	3	331
Production and Mineral Taxes	-	9	-	9	-	9	-	-	-	9
Netback	109	121	5	235	88	323	-	7	4	334
(Gain) Loss on Risk Management	(32)	(28)	-	(60)	1	(59)	-	-	2	(57)
Operating Margin	141	149	5	295	87	382	-	7	2	391

(1) *Found in Note 8 of the interim Consolidated Financial Statements.*

The following table provides the sales volumes used to calculate Netback.

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended September 30, 2017	2016	Nine Months Ended September 30, 2017	2016
Oil Sands				
Foster Creek	**157,850**	76,318	**114,466**	66,229
Christina Lake	**206,338**	80,313	**150,656**	78,838
Total Oil Sands Crude Oil	**364,188**	156,631	**265,122**	145,067
Natural Gas (MMcf per day)	**6**	18	**11**	17
Deep Basin				
Total Liquids	**32,864**	-	**16,706**	-
Natural Gas (MMcf per day)	**495**	-	**251**	-
Conventional				
Heavy Oil	**25,047**	27,953	**26,448**	28,999
Light and Medium Oil	**27,494**	25,359	**26,477**	26,322
Natural Gas Liquids ("NGLs")	**1,201**	1,074	**1,128**	1,027
Total Conventional Liquids	**53,742**	54,386	**54,053**	56,348
Natural Gas (MMcf per day)	**350**	374	**351**	382
Total Liquids Sales	**450,794**	211,017	**335,881**	201,415
Total Sales (BOE per day)	**592,591**	276,350	**438,028**	267,915