MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE PERIOD ENDED JUNE 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 July 26, 2017, should be read in conjunction with our June 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 July 26, 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 six months ended June 30, 2017, reflects the closing of the Acquisition (as defined in this MD&A) on May 17, 2017. See the Transformational Acquisition section of this MD&A for more details. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus Management prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, 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 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 June 30, 2017, we had an enterprise value of approximately $24 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 six months ended June 30, 2017 was approximately 284,565 barrels per day, our average natural gas production was 492 MMcf per day, and our total reported production was 366,556 BOE per day. The refining operations processed an average of 428,000 gross barrels per day of crude oil feedstock into an average of 455,000 gross barrels per day of refined products.

Oil Sands and Deep Basin Acquisition

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 their western Canadian conventional crude oil and natural gas assets in Alberta and British Columbia (the "Acquisition").

The Acquisition provides us with control over our oil sands operations, doubles our oil sands production, and almost doubles our proved bitumen reserves. In addition, the Acquisition provides a second growth platform with more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia (collectively, the "Deep Basin Assets"). The Deep Basin Assets are expected to provide short-cycle development opportunities that complement our long-term oil sands growth portfolio.

Concurrent with the March 29, 2017 announcement of the Acquisition, we commenced marketing for sale our Pelican Lake heavy oil assets, including the adjacent Grand Rapids project in the Greater Pelican Lake region, and our Suffield crude oil and natural gas assets in southern Alberta to help fund the Acquisition. On June 20, 2017, we announced our intention to divest the remainder of our legacy Conventional assets, including our Palliser assets in southern Alberta and our Weyburn oil operation in southern Saskatchewan. Our Conventional segment has been classified as a discontinued operation in our interim Consolidated Financial Statements.

Our Strategy

We have updated our strategy to reflect 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 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, namely 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.

	Six Months Ended June 30, 2017	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Margin	**791**	**3**
Capital Investment	**384**	**3**
Operating Margin Net of Related Capital Investment	**407**	**-**

Deep Basin

The Deep Basin includes approximately three million net acres of land rich in natural gas and natural gas liquids. The assets are located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas and include interests in numerous natural gas processing facilities. 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 – June 30, 2017**
Operating Margin	**55**
Capital Investment	**13**
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 all assets within our Conventional segment. This includes our Pelican Lake heavy oil assets, our Suffield crude oil and natural gas assets, our carbon dioxide ("CO_2") enhanced oil recovery project at Weyburn, and our Palliser assets in southern Alberta. 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.

	Six Months Ended June 30, 2017	
($ millions)	**Liquids**	**Natural Gas**
Operating Margin	**214**	**89**
Capital Investment	**132**	**6**
Operating Margin Net of Related Capital Investment	**82**	**83**

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 allows 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)	**Six Months Ended June 30, 2017**
Operating Margin	**73**
Capital Investment	**86**
Operating Margin Net of Related Capital Investment	**(13)**

OIL SANDS AND DEEP BASIN ACQUISITION

On May 17, 2017, we closed an acquisition acquiring ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' western Canadian conventional assets in Alberta and British Columbia. The Acquisition provides us with control over our oil sands operations, doubles our oil sands production, and almost doubles our proved bitumen reserves. The Deep Basin Assets provide an additional growth platform 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.

Total consideration for the Acquisition includes US$10.6 billion in cash, before adjustments, and 208 million Cenovus common shares. To finance the cash portion of the purchase price, we:

- Completed a Bought-Deal Common Share Offering on April 6, 2017 for 187.5 million common shares at a price of $16.00 per share, raising gross proceeds of $3.0 billion;
- Completed an offering in the U.S. on April 7, 2017 for US$2.9 billion of senior unsecured notes – 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;
- Borrowed $3.6 billion under a committed asset sale bridge credit facility ("Bridge Facility"); and
- Funded the remainder of the purchase price through cash on hand and a draw on our existing committed credit facility.

The committed Bridge Facility consists of three tranches which mature 12 months, 18 months and 24 months, respectively, following the Acquisition closing date. We expect to repay the committed Bridge Facility through the sale of certain assets including our legacy Conventional assets.

The Acquisition has an effective date of January 1, 2017. The majority of the purchase price was allocated to Property, Plant and Equipment ("PP&E"), Exploration and Evaluation ("E&E") assets, and goodwill. Refer to Note 4 in the interim Consolidated Financial Statements for a summary of the recognized amounts of acquired assets and liabilities assumed at the date of the Acquisition. For accounting purposes, total consideration includes $361 million related to a contingent payment. See the Corporate and Eliminations section of this MD&A for more details.

Prior to the Acquisition, Cenovus's 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, Cenovus controls 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.

The safe and efficient integration of the Deep Basin Assets is 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.

Additional information on the Acquisition is available in 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 Acquisitions Report dated July 19, 2017, both available on SEDAR and EDGAR.

QUARTERLY HIGHLIGHTS

We successfully closed the Acquisition in the second quarter of 2017, resulting in control of our oil sands operations and more than doubling our total production. Incremental production from the Acquisition was 297,720 BOE per day for the period May 17 to June 30, 2017 or 147,224 BOE per day for the three months ended June 30, 2017. Our previously announced divestiture process for the Pelican Lake and Suffield assets is progressing well and is on track. On June 20, 2017, we announced our plan to divest our Palliser asset in southern Alberta and our Weyburn oil operation in southern Saskatchewan. Proceeds from the sale of these assets will be used to repay the committed Bridge Facility and deleverage our balance sheet.

During the quarter, crude oil prices continued to be volatile. Although West Texas Intermediate ("WTI") averaged approximately US$48 per barrel, a six percent increase from the same period in 2016, it ranged from a high of US$53.40 per barrel to a low of US$42.53 per barrel. In addition, AECO averaged $2.77 per Mcf, more than doubling from the second quarter of 2016. AECO ranged from a high of $3.03 per Mcf to a low of $2.15 per Mcf. Our average sales price increased 29 percent from 2016, contributing to a companywide Netback of $18.74 per BOE in the second 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 second quarter, we:

- Increased total liquids production by 68 percent from the second quarter of 2016, primarily due to incremental production volumes from the Acquisition as well as from Foster Creek phase G and Christina Lake phase F, both of which started up in the second half of 2016;
- Generated combined upstream revenues, including the Conventional segment, of $2,082 million compared with $967 million in 2016, primarily related to increased sales volumes and higher liquids sales prices;
- Reported upstream operating costs, including the Conventional segment, of $387 million, an increase of $176 million compared with the second quarter of 2016 primarily due to the Acquisition, higher fuel costs as a result of an increase in natural gas prices, and costs related to Foster Creek turnaround activities;
- Achieved Cash From Operating Activities and Adjusted Funds Flow of $1,239 million and $792 million, respectively, an increase from the second quarter of 2016 of $1,034 million and $352 million, respectively; and
- Recorded net earnings of $2.6 billion, which included an after-tax revaluation gain of $1.8 billion on our pre-existing interest in FCCL.

OPERATING RESULTS

Our upstream assets continued to perform well in the three and six months ended June 30, 2017. Total production increased primarily due to the Acquisition and our recent oil sands expansion phases.

Production Volumes

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	**Percent Change**	2016	**2017**	**Percent Change**	2016
Liquids (barrels per day)						
Oil Sands						
Foster Creek	**107,859**	**67%**	64,544	**94,437**	**51%**	62,713
Christina Lake	**153,953**	**97%**	78,060	**127,442**	**64%**	77,577
	261,812	**84%**	142,604	**221,879**	**58%**	140,290
Deep Basin						
Light and Medium Oil	**3,059**	**-%**	-	**1,538**	**-%**	-
NGLs	**13,835**	**-%**	-	**6,956**	**-%**	-
	16,894	**-%**	-	**8,494**	**-%**	-
Conventional (Discontinued Operations)						
Heavy Oil	**26,593**	**(7)%**	28,500	**26,933**	**(10)%**	29,873
Light and Medium Oil	**27,233**	**4%**	26,177	**26,167**	**(2)%**	26,649
NGLs	**1,132**	**42%**	799	**1,090**	**9%**	1,003
	54,958	**(1)%**	55,476	**54,190**	**(6)%**	57,525
Total Liquids Production (barrels per day)	**333,664**	**68%**	198,080	**284,563**	**44%**	197,815
Natural Gas (MMcf per day)						
Oil Sands	**12**	**(33)%**	18	**13**	**(24)%**	17
Deep Basin	**253**	**-%**	-	**127**	**-%**	-
Conventional (Discontinued Operations)	**355**	**(7)%**	381	**352**	**(9)%**	386
Total Natural Gas Production (MMcf per day)	**620**	**55%**	399	**492**	**22%**	403
Total Production (BOE per day)	**436,929**	**65%**	264,580	**366,556**	**38%**	264,982

Production at Foster Creek and Christina Lake was higher in the three and six months ended June 30, 2017 due to the incremental production volumes from the Acquisition and expansion phases, partially offset by the impact of a 20-day planned turnaround, including ramp down and ramp up, at Foster Creek. The planned turnaround was the largest scale turnaround executed to date at Foster Creek. The increase in production at Foster Creek and Christina Lake from May 17, 2017 to June 30, 2017, due to the Acquisition, was 73,880 barrels per day and 104,567 barrels per day, respectively.

Total production from the Deep Basin for the 45 days of operations averaged 119,273 BOE per day, equivalent to 58,981 BOE per day for the three months ended June 30, 2017, and 29,654 BOE per day for the six months ended June 30, 2017. Deep Basin liquids production from May 17, 2017 to June 30, 2017 was 34,163 barrels per day, equivalent to 16,894 barrels per day for the three months ended June 30, 2017 and 8,494 barrels per day for the six months ended June 30, 2017.

Our Conventional liquids production declined in the second quarter and on a year-to-date basis compared to 2016 primarily due to expected natural declines, partially offset by an increase in production associated with the tight oil drilling program in southern Alberta. In the second quarter of 2016, production at Pelican Lake was shut-down for two days as a safety precaution due to a nearby forest fire resulting in lost production of approximately 650 barrels per day for the quarter.

In the second quarter and on a year-to-date basis, our natural gas production increased 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 45 days of operation was approximately 512 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 June 30,		**Six Months Ended June 30,**	
($/BOE)	**2017**	2016	**2017**	2016
Sales Price	**35.58**	27.56	**35.89**	21.41
Royalties	**2.34**	1.51	**2.62**	1.16
Transportation and Blending	**4.78**	5.07	**4.55**	4.79
Operating Expenses	**9.59**	8.89	**9.67**	9.52
Production and Mineral Taxes	**0.13**	0.12	**0.16**	0.10
Netback Excluding Realized Risk Management [(1)]	**18.74**	11.97	**18.89**	5.84
Realized Risk Management Gain (Loss)	**0.28**	1.46	**(1.21)**	3.81
Netback Including Realized Risk Management [(1)]	**19.02**	13.43	**17.68**	9.65

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

Our average Netback for the second quarter of 2017 and on a year-to-date basis, excluding realized risk management gains and losses, was substantially higher compared with 2016. The rise in our average Netback was primarily due to increased sales prices, consistent with the rise in benchmark prices, a weakening of the Canadian dollar relative to the U.S. dollar, and the increase in diversity of products with higher light and medium crude oil and NGLs being produced as a result of the Acquisition, partially offset by higher royalties. On a year-to-date basis, the weakening of the Canadian dollar compared with 2016 had a positive impact on our sales price of approximately $0.10 per BOE.

Refining

In the second quarter, crude oil runs and refined product output declined slightly compared with 2016 primarily due to unplanned maintenance at both Refineries. On a year-to-date basis, crude oil runs and refined product output declined due to the larger scope of the planned turnarounds at both Refineries during the first quarter of 2017 compared to 2016. In the three and six months ended June 30, 2017, lower heavy crude oil volumes were processed due to optimization of the total crude input slate.

	Three Months Ended June 30,			**Six Months Ended June 30,**		
	2017	**Percent Change**	2016	**2017**	**Percent Change**	2016
Crude Oil Runs [(1)] (Mbbls/d)	**449**	**(2)%**	458	**428**	**(4)%**	446
Heavy Crude Oil [(1)]	**201**	**(12)%**	228	**201**	**(14)%**	235
Refined Product [(1)] (Mbbls/d)	**476**	**(1)%**	483	**455**	**(4)%**	472
Crude Utilization [(1)] (percent)	**98**	**(2)%**	100	**93**	**(4)%**	97

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

Operating Margin from Refining and Marketing in the three and six months ended June 30, 2017 was $20 million and $73 million, respectively (2016 – $193 million and $170 million, respectively). The decline in the second quarter was primarily due to a decrease in our gross margin, consistent with narrowing heavy crude oil differentials and lower average market crack spreads, partially offset by a decline in realized risk management losses in the second quarter of 2017 and the weakening of the Canadian dollar. On a year-to-date basis, the decline in Operating Margin was primarily due to narrowing of heavy crude oil differentials, lower crude utilization rates, higher operating costs and lower margins on the sale of secondary products.

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 June 30, 2017 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)]

	Six Months Ended June 30,					
(US$/bbl, unless otherwise indicated)	**2017**	2016	**Percent Change**	**Q2 2017**	Q1 2017	Q2 2016
Crude Oil Prices						
Brent						
Average	**52.79**	41.03	**29%**	**50.92**	54.66	46.97
End of Period	**47.92**	49.68	**(4)%**	**47.92**	52.83	49.68
WTI						
Average	**50.10**	39.52	**27%**	**48.29**	51.91	45.59
End of Period	**46.04**	48.33	**(5)%**	**46.04**	50.60	48.33
Average Differential Brent-WTI	**2.69**	1.51	**78%**	**2.63**	2.75	1.38
WCS						
Average	**37.25**	25.75	**45%**	**37.16**	37.33	32.29
Average (C$/bbl)	**49.67**	34.24	**45%**	**49.95**	49.38	41.61
End of Period	**36.36**	35.79	**2%**	**36.36**	39.77	35.79
Average Differential WTI-WCS	**12.85**	13.77	**(7)%**	**11.13**	14.58	13.30
Condensate (C5 @ Edmonton)						
Average [(2)]	**50.35**	39.23	**28%**	**48.44**	52.26	44.07
Average Differential WTI-Condensate (Premium)/Discount	**(0.25)**	0.29	**(186)%**	**(0.15)**	(0.35)	1.52
Average Differential WCS-Condensate (Premium)/Discount	**(13.10)**	(13.48)	**(3)%**	**(11.28)**	(14.93)	(11.78)
Mixed Sweet Blend ("MSW" @ Edmonton)						
Average	**47.20**	36.13	**31%**	**46.03**	48.37	42.51
End of Period	**43.66**	46.19	**(5)%**	**43.66**	50.07	46.19
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**63.28**	53.12	**19%**	**63.44**	63.13	64.25
Chicago Ultra-low Sulphur Diesel ("ULSD")	**63.02**	51.98	**21%**	**62.18**	63.86	59.40
Refining Margin: Average 3-2-1 Crack Spreads [(3)]						
Chicago	**13.16**	13.36	**(1)%**	**14.78**	11.54	17.15
Average Natural Gas Prices						
AECO (C$/Mcf)	**2.86**	1.68	**70%**	**2.77**	2.94	1.25
NYMEX (US$/Mcf)	**3.25**	2.02	**61%**	**3.18**	3.32	1.95
Basis Differential NYMEX-AECO (US$/Mcf)	**1.12**	0.78	**44%**	**1.13**	1.10	0.99
Foreign Exchange Rate (US$ per C$1)						
Average	**0.750**	0.752	**-%**	**0.744**	0.756	0.776

(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 second quarter of 2017 was $65.11 per barrel (2016 – $56.79 per barrel) and for the six months ended June 30, 2017 was $67.13 per barrel (2016 – $52.17 per barrel).

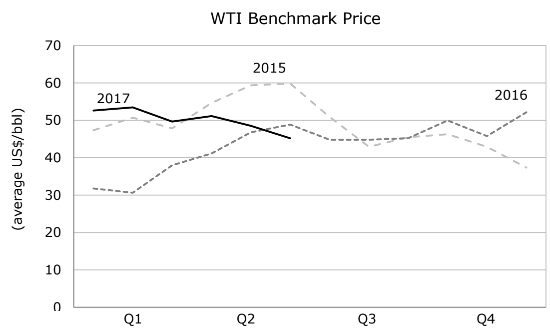
(3) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.

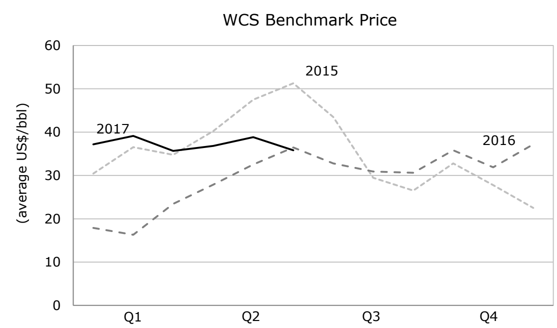
Crude Oil Benchmarks

The average Brent, WTI and Western Canadian Select ("WCS") benchmark prices improved in the first six months of 2017 as compliance with the production cuts agreed to in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries ("OPEC") led to wide-spread market expectations at the beginning of 2017 of an accelerated return to normal inventory levels without supporting supply and demand drivers. However, near the end of the first half of 2017 prices continued to be volatile as crude oil and product inventories did not decrease as expected partially due to the rising U.S. rig count and growing supply from the U.S., Libya and Nigeria.

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 second quarter of 2016 and on a year-to-date basis due to the combination of growing U.S. crude oil supply and OPEC's compliance with production cuts.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in the second quarter of 2017 and on a year-to-date basis compared with 2016. The differential narrowed due to significant production outages in Alberta and OPEC cuts.





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.

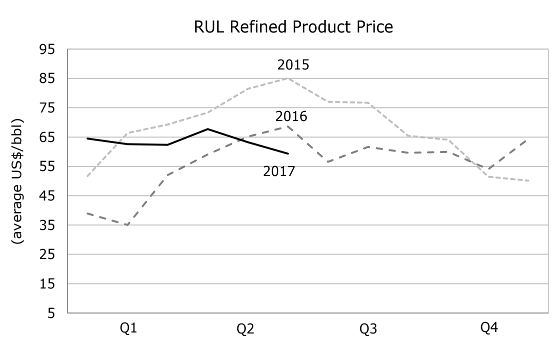
The average WTI-Condensate differential narrowed in the second quarter of 2017 and on a year-to-date basis as a result of seasonal changes in blending requirements.

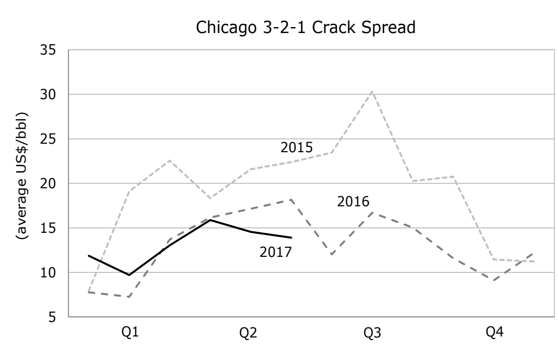
MSW, is an Alberta based, Canadian light sweet crude oil benchmark that is representative of Canadian conventional production and comparable to the crude oil produced by our Deep Basin Assets.

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 second quarter of 2017 and on a year-to-date basis primarily due to higher crude oil prices, partially offset by higher refinery utilization which increased supply. Average Chicago 3-2-1 crack spreads declined during the three and six months ended June 30, 2017 compared with 2016 due to higher refinery utilization. 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 natural gas prices in the second quarter and on a year-to-date basis increased significantly compared with 2016. Natural gas prices strengthened in 2017 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 2016, natural gas prices 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

Revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. A decrease in the value of the Canadian dollar compared with the U.S. dollar has a positive impact on our reported results. Likewise, as the Canadian dollar strengthens, our reported results are lower. In addition to our revenues being denominated in U.S. dollars, a 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 second quarter and on a year-to-date basis, the Canadian dollar weakened relative to the U.S. dollar due to differing interest rate expectations between Canada and the U.S. The weakening of the Canadian dollar in the first half of the year, compared with 2016, had a positive impact of approximately $22 million on our revenues, including our Conventional segment. As at June 30, 2017, the Canadian dollar was stronger relative to the U.S. dollar on December 31, 2016, which resulted in $335 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The Acquisition and improvements in commodity prices in the first half of 2017 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)	Six Months Ended June 30,		2017		2016				2015		
	2017	2016	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Revenues (1) (2)	**7,578**	4,737	**4,037**	3,541	3,324	2,945	2,746	1,991	2,601	2,905	3,244
Operating Margin (2)											
Total Operating Margin	**1,228**	685	**778**	450	595	487	541	144	357	602	932
From Continuing Operations	**924**	446	**619**	305	442	335	424	22	153	360	631
Cash From Operating Activities											
Total Cash From Operating Activities	**1,567**	387	**1,239**	328	164	310	205	182	322	542	335
From Continuing Operations	**1,297**	215	**1,102**	94	22	189	121	94	123	366	86
Adjusted Funds Flow (3)											
Total Adjusted Funds Flow	**1,115**	466	**792**	323	535	422	440	26	275	444	477
From Continuing Operations	**833**	287	**650**	(65)	382	296	352	(65)	71	266	227
Operating Earnings (Loss) (3)											
Total Operating Earnings (Loss)	**359**	(462)	**398**	(39)	321	(236)	(39)	(423)	(438)	(28)	151
Per Share – Diluted ($)	**0.37**	(0.55)	**0.36**	(0.05)	0.39	(0.28)	(0.05)	(0.51)	(0.53)	(0.03)	0.18
From Continuing Operations	**305**	(272)	**344**	(39)	21	(40)	(3)	(269)	(245)	(23)	201
Per Share – Diluted ($)	**0.31**	(0.33)	**0.31**	(0.05)	0.03	(0.05)	-	(0.32)	(0.29)	(0.03)	0.24
Net Earnings (Loss) From Continuing Operations	**2,792**	(195)	**2,581**	211	(209)	(55)	(231)	36	(448)	1,806	176
Per Share – Basic and Diluted ($)	**2.87**	(0.23)	**2.32**	0.25	(0.25)	(0.07)	(0.28)	0.04	(0.54)	2.17	0.21
Net Earnings (Loss)	**2,851**	(385)	**2,640**	211	91	(251)	(267)	(118)	(641)	1,801	126
Per Share – Basic and Diluted ($)	**2.93**	(0.46)	**2.37**	0.25	0.11	(0.30)	(0.32)	(0.14)	(0.77)	2.16	0.15
Capital Investment (4)	**640**	559	**327**	313	259	208	236	323	428	400	357
Dividends											
Cash Dividends	**102**	83	**61**	41	42	41	42	41	132	133	125
In Shares from Treasury	**-**	-	**-**	-	-	-	-	-	-	-	98
Per Share ($)	**0.10**	0.10	**0.05**	0.05	0.05	0.05	0.05	0.05	0.16	0.16	0.2662

(1) Excludes revenues from discontinued operations. For the three and six months ending June 30, 2017, revenues related to discontinued operations were $336 million and $660 million, respectively (2016 – $261 million and $515 million, respectively). The comparative periods have been restated to reflect discontinued operations.

(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 PP&E, E&E assets, assets held for sale and discontinued operations.

Revenues

($ millions)	Three Months Ended	Six Months Ended
Revenues for the Periods Ended June 30, 2016	**2,746**	**4,737**
Increase (Decrease) due to:		
Oil Sands	**924**	**1,489**
Deep Basin	**116**	**116**
Refining and Marketing	**268**	**1,284**
Corporate and Eliminations	**(17)**	**(48)**
Revenues for the Periods Ended June 30, 2017	**4,037**	**7,578**

Combined upstream revenues, excluding Conventional revenues, increased in the second quarter and on a year-to-date basis, compared with 2016. The increase was primarily related to an increase in sales volumes due to the Acquisition and the Foster Creek phase G and Christina Lake phase F expansion phases in our Oil Sands segment, higher commodity prices and the weakening of the Canadian dollar relative to the U.S. dollar. These increases were partially offset by a rise in royalties. Conventional revenues have been reported in net earnings from discontinued operations and are discussed below.

Revenues from our Refining and Marketing segment in the three and six months ended June 30, 2017 increased 13 percent and 35 percent, respectively. Refining revenues rose due to the increase in refined product pricing, consistent with higher average Chicago refined product benchmark prices and the weakening of the Canadian dollar relative to the U.S. dollar. The rise was partially offset by decreased refined product output. Revenues from third-party crude oil and natural gas sales undertaken by the marketing group increased in the three and six months ended June 30, 2017 compared with 2016. In the second quarter, the increase was primarily due to higher crude oil and natural gas sales prices, partially offset by a decrease in purchased crude oil, natural gas and condensate volumes. On a year-to-date basis, the rise in marketing revenues was 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.

We intend to divest all of our legacy Conventional assets. As such, our Conventional segment has been classified as a discontinued operation. For the three and six months ended June 30, 2017, Conventional revenues were $336 million and $660 million, respectively. The increase in revenues compared with 2016 was primarily due to higher commodity prices and the weakening of the Canadian dollar relative to the U.S. dollar. These increases were partially offset by a rise in royalties.

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

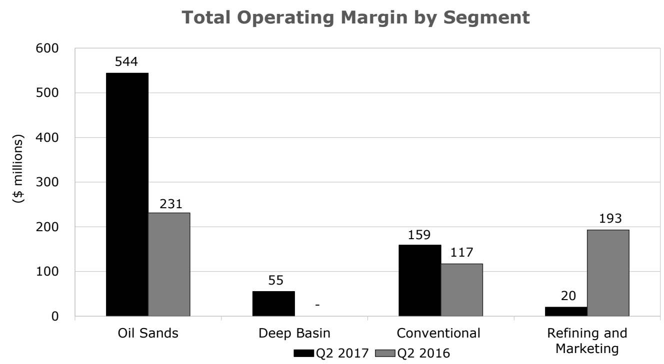
	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Revenues	**4,479**	3,096	**8,442**	5,408
(Add) Deduct:				
Purchased Product	**2,183**	1,712	**4,513**	3,140
Transportation and Blending	**943**	440	**1,560**	891
Operating Expenses	**579**	393	**1,048**	845
Production and Mineral Taxes	**5**	3	**10**	5
Realized (Gain) Loss on Risk Management Activities	**(9)**	7	**83**	(158)
Total Operating Margin (1)	**778**	541	**1,228**	685

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

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

Total Operating Margin increased 44 percent in the second quarter of 2017 compared with 2016 primarily due to:

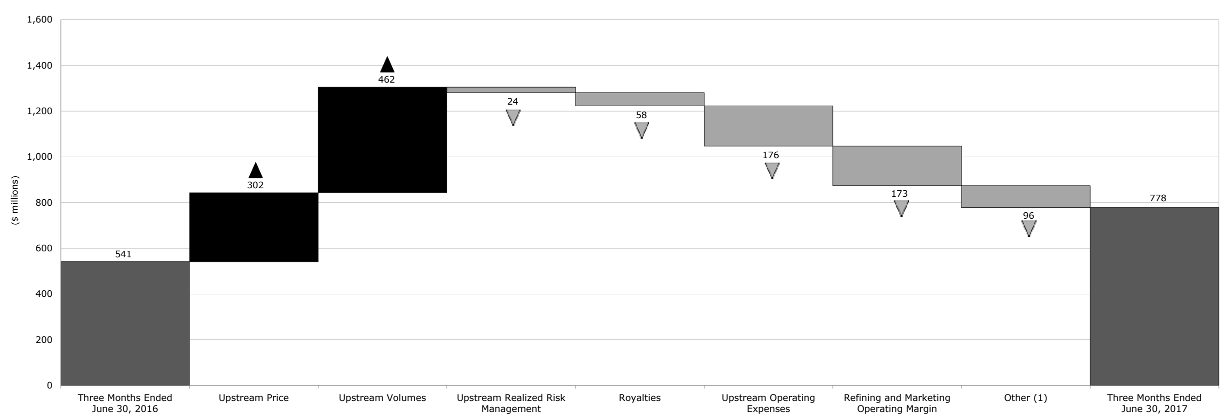
- A 72 percent increase in our liquids sales volumes as well as a 55 percent rise in our natural gas sales volumes, primarily related to the Acquisition and our recent oil sands expansion phases; and
- Our average liquids sales price rising 22 percent and our average natural gas sales price increasing 84 percent, consistent with higher associated benchmark prices and the increase in diversity of products with higher light and medium crude oil and NGLs being produced by our Deep Basin Assets.



These increases in Operating Margin were partially offset by:

- A rise in transportation and blending expenses 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 fuel costs as a result of an increase in natural gas prices, and a rise in repairs and maintenance activities primarily related to the planned turnaround at Foster Creek that was in line with budget;
- Lower Operating Margin from Refining and Marketing due to narrowing heavy crude oil differentials and a decline in average market crack spreads, partially offset by lower realized risk management losses;
- 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; and
- Realized risk management gains of $11 million, associated with our upstream assets, compared with gains of $35 million in the second quarter of 2016.

Total Operating Margin Variance

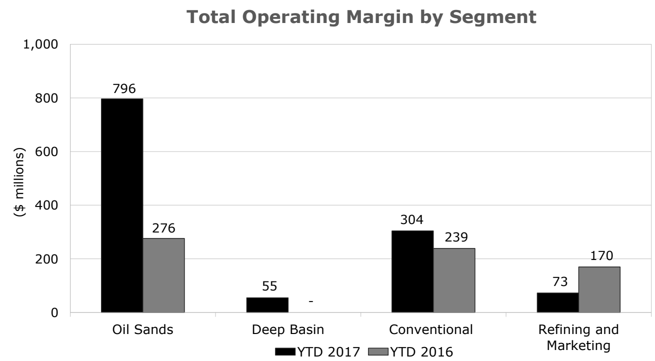


(1) *Other includes the value of condensate sold as heavy oil blend recorded in revenues and condensate costs recorded in transportation and blending expense. The crude oil price excludes the impact of condensate purchases.*

Six Months Ended June 30, 2017 Compared With June 30, 2016

Operating Margin increased 79 percent in the first six months of 2017 compared with 2016 primarily due to:

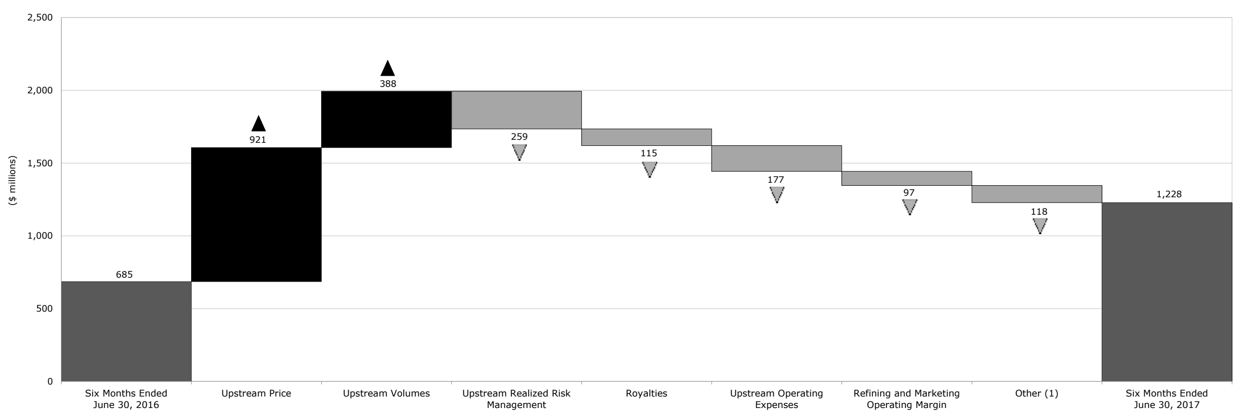
- Our average liquids sales price increasing 67 percent and our average natural gas sales price rising 50 percent, consistent with higher associated benchmark prices and the increase in diversity of products with higher light and medium crude oil and NGLs being produced by our Deep Basin Assets; and
- A 41 percent increase in our liquids sales volumes as well as a 22 percent rise in our natural gas sales volumes, primarily related to the Acquisition and our recent oil sand expansion phases.



These increases to Operating Margin were partially offset by:

- A rise in transportation and blending expenses 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;
- Realized risk management losses of $79 million, associated with our upstream assets, compared with gains of $180 million in 2016;
- An increase in operating expenses primarily due to the Acquisition and higher fuel costs related to the increase in natural gas pricing;
- 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; and
- Lower Operating Margin from Refining and Marketing due to narrowing heavy crude oil differentials, a decline in crude utilization rates and higher operating costs related to the larger scope of turnaround activities in the first quarter, and lower margins on the sale of secondary products.

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.

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Revenues	**4,143**	2,835	**7,782**	4,893
(Add) Deduct:				
Purchased Product	**2,183**	1,712	**4,513**	3,140
Transportation and Blending	**889**	395	**1,455**	799
Operating Expenses	**464**	286	**823**	616
Production and Mineral Taxes	**-**	-	**-**	-
Realized (Gain) Loss on Risk Management Activities	**(12)**	18	**67**	(108)
Operating Margin From Continuing Operations	**619**	424	**924**	446

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. Net change in other assets and liabilities is composed of site restoration costs and pension funding. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents and risk management.

Total Cash From Operating Activities and Adjusted Funds Flow

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Cash From Operating Activities (1)	**1,239**	205	**1,567**	387
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(25)**	(17)	**(56)**	(46)
Net Change in Non-Cash Working Capital	**472**	(218)	**508**	(33)
Adjusted Funds Flow (1)	**792**	440	**1,115**	466

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

In the three and six months ended June 30, 2017, Cash From Operating Activities and Adjusted Funds Flow increased primarily as a result of higher Operating Margin, as discussed above, a realized risk management gain on foreign exchange contracts due to hedging activity undertaken to support the Acquisition, and a higher current tax recovery, partially offset by higher finance costs primarily associated with additional debt incurred to finance the Acquisition.

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

The change in non-cash working capital for the six months ended June 30, 2017 was primarily due to a decline in accounts receivable, partially offset by an increase in income tax receivable. For the six months ended June 30, 2016, the change in non-cash working capital was primarily due to an increase in accounts receivable and a rise in inventory, 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 June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Cash From Operating Activities From Continuing Operations	**1,102**	121	**1,297**	215
(Add) Deduct:				
Net Change in Other Assets and Liabilities	**(20)**	(13)	**(44)**	(39)
Net Change in Non-Cash Working Capital	**472**	(218)	**508**	(33)
Adjusted Funds Flow From Continuing Operations	**650**	352	**833**	287

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

($ millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Earnings (Loss), Before Income Tax [1]	**3,342**	(348)	**3,602**	(683)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [2]	**(132)**	284	**(411)**	433
Non-Operating Unrealized Foreign Exchange (Gain) Loss [3]	**(279)**	18	**(335)**	(395)
Revaluation (Gain)	**(2,524)**	-	**(2,524)**	-
(Gain) Loss on Divestiture of Assets	**-**	1	**1**	1
Operating Earnings (Loss), Before Income Tax	**407**	(45)	**333**	(644)
Income Tax Expense (Recovery)	**9**	(6)	**(26)**	(182)
Operating Earnings (Loss)	**398**	(39)	**359**	(462)

(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 and six months ended June 30, 2017 compared with 2016 primarily due to higher Cash from Operating Activities and Adjusted Funds Flow, as discussed above, unrealized foreign exchange gains related to operating activities as compared with losses in 2016, and the re-measurement of the contingent payment. In the three months ended June 30, 2017, the increase in Operating Earnings was partially offset by an increase in DD&A. On a year-to-date basis, DD&A declined slightly improving Operating Earnings.

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 June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Earnings (Loss) From Continuing Operations, Before Income Tax	**3,263**	(296)	**3,523**	(406)
Add (Deduct):				
Unrealized Risk Management (Gain) Loss [1]	**(132)**	284	**(411)**	433
Non-Operating Unrealized Foreign Exchange (Gain) Loss [2]	**(279)**	18	**(335)**	(395)
Revaluation (Gain)	**(2,524)**	-	**(2,524)**	-
(Gain) Loss on Divestiture of Assets	**-**	1	**1**	1
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**328**	7	**254**	(367)
Income Tax Expense (Recovery)	**(16)**	10	**(51)**	(95)
Operating Earnings (Loss) From Continuing Operations	**344**	(3)	**305**	(272)

(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	Six Months Ended
Net Earnings (Loss) for the Periods Ended June 30, 2016	**(267)**	**(385)**
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**195**	**478**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**416**	**844**
Unrealized Foreign Exchange Gain (Loss)	**414**	**77**
Revaluation (Gain)	**2,524**	**2,524**
Re-measurement of Contingent Payment	**66**	**66**
Gain (Loss) on Divestiture of Assets	**1**	**-**
Expenses [(1)]	**105**	**123**
DD&A	**(162)**	**(184)**
Exploration Expense	**-**	**1**
Income Tax Recovery (Expense)	**(747)**	**(942)**
Earnings From Discontinued Operations, Net of Tax	**95**	**249**
Net Earnings (Loss) for the Periods Ended June 30, 2017	**2,640**	**2,851**

(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 Earnings for the three months ended June 30, 2017 increased primarily due to:

- A revaluation gain of $2,524 million related to the deemed disposition of our pre-existing interest in FCCL. See the Corporate and Eliminations or the Oil Sands and Deep Basin Acquisition sections of this MD&A for more details;
- Higher Operating Earnings, as discussed above;
- Unrealized risk management gains of $132 million in the quarter compared with unrealized losses of $284 million in the second quarter of 2016; and
- Non-operating unrealized foreign exchange gains of $279 million related to the translation of our U.S. dollar denominated debt compared with unrealized losses of $18 million in 2016.

These decreases were partially offset by higher deferred income tax expense in 2017 primarily due to the gain on the revaluation of our pre-existing partnership interest in FCCL in connection with the Acquisition compared with a deferred tax recovery in 2016.

Net Earnings improved for the six months ended June 30, 2017 primarily due to the revaluation gain, unrealized risk management gains of $411 million compared with unrealized losses of $433 million in 2016, and higher Operating Earnings, as discussed above. These increases were partially offset by a deferred income tax expense compared with a deferred income tax recovery in 2016 and non-operating unrealized foreign exchange gains of $335 million compared with unrealized gains of $395 million in 2016.

Net Capital Investment

($ millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Oil Sands	**215**	139	**387**	366
Deep Basin	**13**	-	**13**	-
Conventional	**50**	34	**138**	73
Refining and Marketing	**40**	53	**86**	105
Corporate and Eliminations	**9**	10	**16**	15
Capital Investment	**327**	236	**640**	559
Acquisitions [(1)]	**29,835**	11	**29,835**	11
Divestitures [(1)]	**(9,081)**	-	**(9,081)**	-
Net Capital Investment [(2)]	**21,081**	247	**21,394**	570

(1) *In connection with the Acquisition, 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.*
(2) *Includes expenditures on PP&E, E&E assets, assets held for sale and discontinued operations.*

Capital investment in the three months and six months ended June 30, 2017 increased 39 percent and 14 percent, respectively compared to 2016. In the first half of 2017, Oil Sands capital investment focused primarily on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells, near-term expansion phases, and progression of certain emerging assets; and for Christina Lake expansion phase G. Deep Basin capital investment in the first 45 days of ownership focused on asset development planning and the commencement of our drilling program. Drilling activity will be focused on drilling horizontal production wells targeting liquids rich gas in the Deep Basin corridor. In the first half of 2017, Conventional capital investment focused on sustaining capital and the tight oil drilling program in southern Alberta. Capital investment in the Refining and Marketing segment focused on 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

We are intently focused on completing divestitures of our legacy Conventional assets in order to deleverage our balance sheet. Repaying the committed Bridge Facility is our number one priority.

Our disciplined approach to long-term 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.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2017**	2016	**2017**	2016
Adjusted Funds Flow (1)	**792**	440	**1,115**	466
Capital Investment (Sustaining and Growth)	**327**	236	**640**	559
Free Funds Flow (1) (2)	**465**	204	**475**	(93)
Cash Dividends	**61**	42	**102**	83
	404	162	**373**	(176)

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

Upon further review of our capital program following our June 20, 2017 news release, we updated our 2017 guidance estimates, including future capital investment, as cost savings opportunities have been identified. We now expect to spend between $1.6 billion and $1.8 billion. Guidance has decreased from June 20, 2017 by approximately 11 percent.

In the first half of 2016, capital investment in excess of Adjusted Funds Flow was funded through our cash balance on hand.

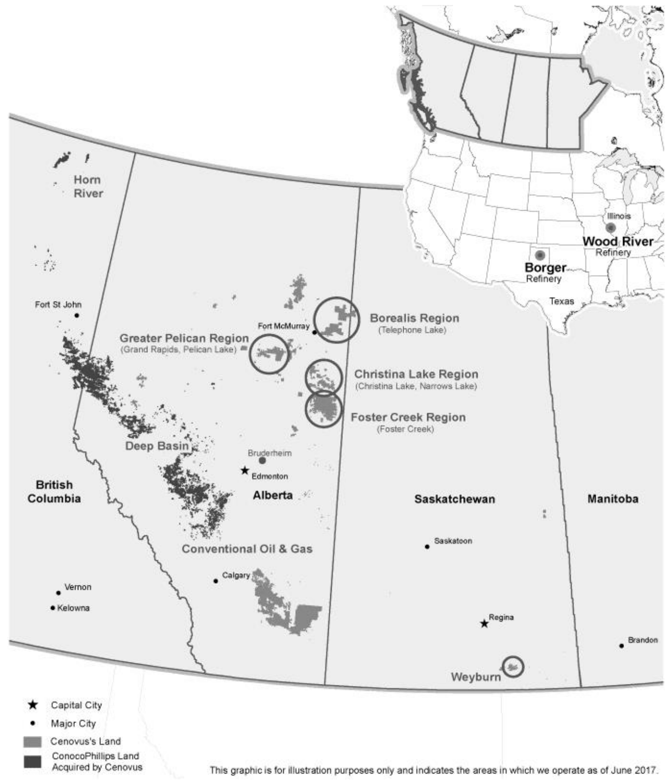
REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as projects in the early stages of development, such as 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 have 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 June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Oil Sands (2)	**1,630**	706	**2,665**	1,176
Deep Basin (3)	**116**	-	**116**	-
Refining and Marketing	**2,397**	2,129	**5,001**	3,717
Corporate and Eliminations	**(106)**	(89)	**(204)**	(156)
	4,037	2,746	**7,578**	4,737

(1) *In the first quarter of 2017, we announced the sale of certain assets, including our Pelican Lake and Suffield assets, as part of our plan to repay the committed Bridge Facility associated with the Acquisition. In the second quarter of 2017, we announced our intention to divest the remaining Conventional segment assets, including our Palliser and Weyburn assets. The Conventional segment has been classified as a discontinued operation. For the three and six months ending June 30, 2017, revenues related to discontinued operations were $336 million and $660 million, respectively (2016 – $261 million and $515 million, respectively).*

(2) *Our second quarter results include 45 days of FCCL operations at 100 percent interest from May 17, 2017 until June 30, 2017. See the Oil Sands and Deep Basin Acquisition section and the Oil Sands segment section of this MD&A for more details.*

(3) *Our second quarter results include 45 days of operations from the Deep Basin Assets from May 17, 2017 until June 30, 2017. See the Oil Sands and Deep Basin Acquisition section and 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 second quarter of 2017 compared with 2016 include:

- Increasing our ownership of FCCL from 50 percent to 100 percent upon closing of the Acquisition on May 17, 2017;
- Increasing crude oil production by 84 percent due to the Acquisition and incremental production volumes from Foster Creek phase G and Christina Lake phase F, both of which started-up in the second half of 2016;
- Crude oil netbacks, excluding realized risk management activities, of $22.34 per barrel, a 55 percent increase from the second quarter of 2016; and
- Generating Operating Margin net of capital investment of $329 million, an increase of $237 million.

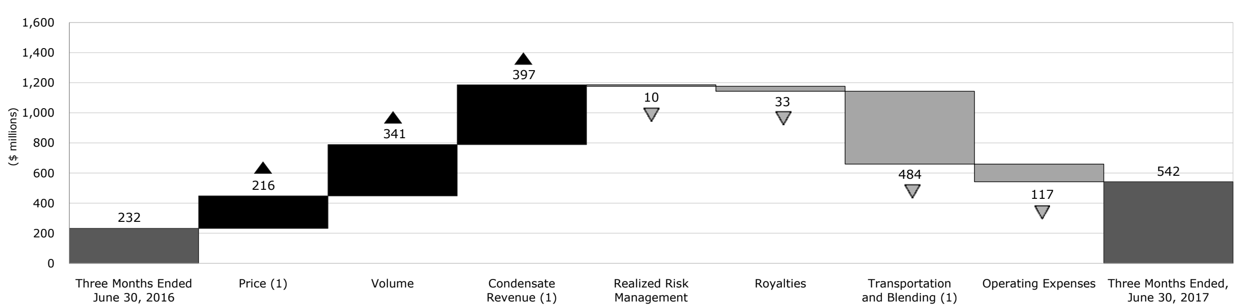
Oil Sands – Crude Oil

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

Financial Results

($ millions)	Three Months Ended June 30, 2017	2016
Gross Sales	**1,661**	707
Less: Royalties	**36**	3
Revenues	**1,625**	704
Expenses		
Transportation and Blending	**879**	395
Operating	**218**	101
(Gain) Loss on Risk Management	**(14)**	(24)
Operating Margin	**542**	232
Capital Investment	**215**	138
Operating Margin Net of Related Capital Investment	**327**	94

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 second quarter of 2017, our average crude oil sales price increased significantly to $39.73 per barrel (2016 – $30.59 per barrel). The rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, the narrowing of the WCS-Condensate differential, and the weakening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US$1.53 per barrel (2016 – discount of US$2.64 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

	Three Months Ended June 30,		
(barrels per day)	**2017**	**Percent Change**	2016
Foster Creek	**107,859**	**67%**	64,544
Christina Lake	**153,953**	**97%**	78,060
	261,812	**84%**	142,604

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 the impact of a 20-day planned turnaround, including ramp down and ramp up, at Foster Creek. The total increase in production volumes related to the Acquisition in the three months ended June 30, 2017 was 36,534 barrels per day. The impact of the planned turnaround was approximately 11,073 barrels per day in the second quarter of 2017.

Production from Christina Lake increased in the three months ended June 30, 2017 primarily due to the Acquisition and incremental production volumes from the phase F expansion. The total increase in production volumes related to the Acquisition in the three months ended June 30, 2017 was 51,709 barrels per day.

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 second quarter, 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 the three months ended June 30, 2017, our royalty calculation was based on net profits as compared with a calculation based on gross revenues for 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

	Three Months Ended June 30,	
(percent)	**2017**	2016
Foster Creek	**7.3**	1.0
Christina Lake	**2.6**	1.2

Royalties increased $33 million in the second quarter compared with 2016, primarily due to an increase in the WTI benchmark price (which determines the royalty rate).

Expenses

Transportation and Blending

Transportation and blending costs increased $484 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 second quarter, 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 due to the Acquisition and ramp up of 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 in the second quarter compared with 2016. We transported an average of 8,280 barrels per day of crude oil by rail (2016 – 5,405 barrels per day).

Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs declined $1.00 per barrel and at Christina Lake transportation costs declined $0.80 per barrel. The decreases were primarily due to an increase in sales volumes and an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs. The decline at Foster Creek was partially offset by an increase in rail costs related to an increase in volumes shipped via unit trains.

Operating

Primary drivers of our operating expenses for the second quarter were workforce, fuel, repairs and maintenance, and chemical costs. Total operating expenses increased $117 million primarily due to the Acquisition, increased fuel costs with the rise in natural gas prices, and higher repairs and maintenance primarily due to the turnaround at Foster Creek.

Per-unit Operating Expenses

($/bbl)	Three Months Ended June 30, 2017	Percent Change	2016
Foster Creek			
Fuel	**2.89**	**76%**	1.64
Non-fuel	**9.42**	**11%**	8.51
Total	**12.31**	**21%**	10.15
Christina Lake			
Fuel	**2.38**	**68%**	1.42
Non-fuel	**4.66**	**(5)%**	4.93
Total	**7.04**	**11%**	6.35
Total	**9.19**	**14%**	8.06

At Foster Creek, per-barrel fuel costs rose compared with 2016 primarily due to higher natural gas prices. Non-fuel operating expenses increased on a per-barrel basis primarily due to higher repairs and maintenance, and fluid and waste handling and trucking costs related to turnaround activities, partially offset by higher production.

At Christina Lake, fuel costs increased on a per-barrel basis in 2017 primarily due to higher natural gas prices. Non-fuel operating expenses declined due to higher production, partially offset by an increase in workforce and chemical costs related to phase F.

Netbacks (1)

	Foster Creek		Christina Lake	
	Three Months Ended June 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**44.38**	33.40	**36.54**	28.31
Royalties	**2.49**	0.23	**0.85**	0.28
Transportation and Blending	**10.44**	11.44	**4.10**	4.90
Operating Expenses	**12.31**	10.15	**7.04**	6.35
Netback Excluding Realized Risk Management	**19.14**	11.58	**24.55**	16.78
Realized Risk Management Gain (Loss)	**1.01**	1.88	**0.34**	1.96
Netback Including Realized Risk Management	**20.15**	13.46	**24.89**	18.74

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

Risk Management

Risk management activities in the second quarter resulted in realized gains of $14 million (2016 – realized gains of $24 million), consistent with our contract prices exceeding average benchmark prices.

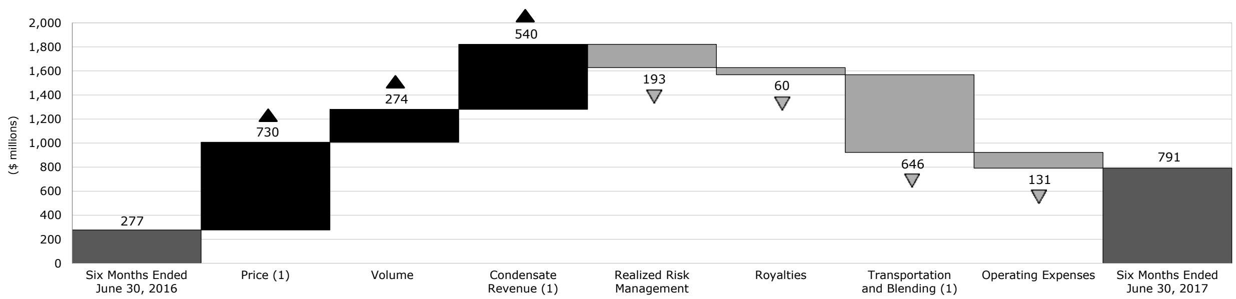
Six Months Ended June 30, 2017 Compared With June 30, 2016

Financial Results

($ millions)	Six Months Ended June 30, 2017	2016
Gross Sales	**2,716**	1,172
Less: Royalties	**63**	3
Revenues	**2,653**	1,169
Expenses		
Transportation and Blending	**1,445**	799
Operating	**354**	223
(Gain) Loss on Risk Management	**63**	(130)
Operating Margin	**791**	277
Capital Investment	**384**	365
Operating Margin Net of Related Capital Investment	**407**	(88)

In 2016, capital investment in excess of Operating Margin from Oil Sands was funded through Operating Margin generated by our Conventional and Refining and Marketing segments, as well as our cash balance on hand.

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 six months ended June 30, 2017, our average crude oil sales price increased significantly to $39.09 per barrel (2016 – $20.28 per barrel). The significant rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend ("CDB") benchmark prices, the narrowing of the WCS-Condensate differential, and the weakening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US$1.66 per barrel (2016 – discount of US$2.30 per barrel).

Production Volumes

(barrels per day)	Six Months Ended June 30, 2017	Percent Change	2016
Foster Creek	**94,437**	**51%**	62,713
Christina Lake	**127,442**	**64%**	77,577
	221,879	**58%**	140,290

Production at Foster Creek was higher compared with 2016 due to incremental production volumes from the phase G expansion and the Acquisition, partially offset by the impact of a 20-day planned turnaround at Foster Creek. Production from Christina Lake increased in the six months ended June 30, 2017 primarily due to the Acquisition and incremental production volumes from the phase F expansion. The total increase in production volumes related to the Acquisition in the six months ended June 30, 2017 was 18,453 barrels per day and 25,998 barrels per day for Foster Creek and Christina Lake, respectively. The impact of the Foster Creek turnaround was approximately 5,567 barrels per day in 2017.

Royalties

Effective Royalty Rates

(percent)	Six Months Ended June 30, **2017**	2016
Foster Creek	**7.8**	0.3
Christina Lake	**2.6**	1.2

Royalties increased $60 million. On a year-to-date basis, our Foster Creek royalty calculation was based on net profits as compared with a calculation based on gross revenues in 2016. Our royalties at Foster Creek increased primarily due to an increase in the WTI benchmark price (which determines 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) and higher sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $646 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 six months ended June 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 ramp up of the expansion phases and the Acquisition.

In addition, rail costs rose as a result of moving higher volumes by rail compared with 2016. We transported an average of 9,370 barrels per day of crude oil by rail (2016 – 3,859 barrels per day).

Per-unit Transportation Expenses

At Foster Creek, per-barrel transportation costs declined $0.80 per barrel and at Christina Lake transportation costs declined $0.99 per barrel. The decreases were primarily due to an increase in sales volumes and an increase in the proportion of Canadian to U.S. sales resulting in lower costs associated with pipeline tariffs. The decline at Foster Creek was partially offset by an increase in rail costs related to an increase in volumes shipped via unit trains.

Operating

Primary drivers of our operating expenses in the first half of 2017 were workforce, fuel, repairs and maintenance, workovers, and chemicals. Total operating expenses increased $131 million primarily due to increased fuel costs with the rise in natural gas prices, the Acquisition, and higher repairs and maintenance primarily due to the turnaround at Foster Creek.

Per-unit Operating Expenses

($/bbl)	Six Months Ended June 30, **2017**	**Percent Change**	2016
Foster Creek			
Fuel	**2.91**	**42%**	2.05
Non-fuel	**8.42**	**(7)%**	9.04
Total	**11.33**	**2%**	11.09
Christina Lake			
Fuel	**2.45**	**44%**	1.70
Non-fuel	**4.97**	**(6)%**	5.30
Total	**7.42**	**6%**	7.00
Total	**9.10**	**4%**	8.79

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 and a true-up of the 2016 emissions charge under the Specified Gas Emitters Regulation ("SGER"), partially offset by higher repairs and maintenance, fluid and waste handling and trucking costs related to turnaround activities, an increase in workover costs due to a higher number of pump changes, and higher electrical consumption.

At Christina Lake, fuel costs rose on a per-barrel basis due to higher natural gas prices. Per-barrel non-fuel operating expenses decreased primarily due to higher production, partially offset by a true-up of the 2016 emissions charged under the SGER, and an increase in workforce and chemical costs related to phase F. Christina Lake's emissions are below the threshold set by the SGER program and generate performance credits which are applied to the charges incurred at Foster Creek.

Netbacks [1]

($/bbl)	Foster Creek 2017	Foster Creek 2016	Christina Lake 2017	Christina Lake 2016
	Six Months Ended June 30,			
Sales Price	**42.79**	22.78	**36.29**	18.33
Royalties	**2.64**	0.04	**0.85**	0.16
Transportation and Blending	**9.29**	10.09	**4.11**	5.10
Operating Expenses	**11.33**	11.09	**7.42**	7.00
Netback Excluding Realized Risk Management	**19.53**	1.56	**23.91**	6.07
Realized Risk Management Gain (Loss)	**(1.84)**	5.63	**(1.44)**	4.77
Netback Including Realized Risk Management	**17.69**	7.19	**22.47**	10.84

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

Risk Management

Risk management activities in the first six months of 2017 resulted in realized losses of $63 million (2016 – realized gains of $130 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 six months ended June 30, 2017, net of internal usage, was 12 MMcf per day and 13 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 $2 million in the second quarter (2016 – $nil) and $3 million on a year-to-date basis (2016 – $1 million), increasing primarily due to higher natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Foster Creek	**120**	68	**190**	157
Christina Lake	**77**	61	**140**	175
	197	129	**330**	332
Narrows Lake	**3**	1	**8**	5
Telephone Lake	**5**	3	**29**	10
Grand Rapids	**1**	1	**1**	6
Other [1]	**9**	5	**19**	13
Capital Investment [2]	**215**	139	**387**	366

(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 the first half of 2017 focused on sustaining capital related to existing production and stratigraphic test wells. In 2016, capital investment remained low due to spending reductions in response to the low commodity price environment.

In the first half of 2017, Christina Lake capital investment focused on sustaining capital related to existing production, the phase G expansion and stratigraphic test wells. Capital investment increased in the second quarter of 2017 compared with 2016 due to our 100 percent ownership of FCCL from May 17, 2017 forward. On a year-to-date basis, capital investment declined in 2017 due to the completion of the phase F expansion. 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 in the first half of 2017 focused on drilling of stratigraphic test wells to further progress the project. Capital investment remained relatively consistent in 2017 compared with 2016.

Emerging Projects

In the first half of 2017, Telephone Lake capital investment focused on the drilling of stratigraphic test wells to further assess the project. In 2017, Telephone Lake capital investment increased compared with 2016. 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

Six Months Ended June 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	**20**	11
Christina Lake	**98**	97	**8**	19
	191	192	**28**	30
Narrows Lake	**2**	-	**-**	-
Telephone Lake	**13**	-	**-**	-
Other	**1**	5	**-**	-
	207	197	**28**	30

(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

Upon further review of our capital program following our June 20, 2017 news release, we updated our 2017 guidance estimate.

Our revised full year 2017 Oil Sands capital investment is forecast to be between $1,000 million and $1,120 million. Guidance has decreased from June 20, 2017 by approximately seven percent.

Foster Creek is currently producing from phases A through G. Capital investment for 2017 is forecast to be between $480 million and $530 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 $450 million and $500 million, focused on sustaining capital and construction of the phase G expansion, which had previously been deferred. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, resumed in the first quarter of 2017 and remains on track. Phase G is expected to start producing in late 2019.

Capital investment at Narrows Lake and our new resource plays in 2017 is forecast to be between $70 million and $90 million, focusing on a stratigraphic test well programs at Telephone Lake and Narrows 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 $9.40 to $9.90 per BOE. Amounts related to assets under construction, assets held for sale, 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 six months ended June 30, 2017, Oil Sands DD&A increased $117 and $139 million, respectively, from 2016. The increase was due to higher sales volumes primarily due to the Acquisition. The average depletion rate for the first six months of 2017 was approximately $10.99 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 and the acquisition of the additional 50 percent interest at fair value.

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.

There was no exploration expense recorded in 2017 (2016 – $1 million).

Assets and Liabilities Held for Sale

Concurrent with the announcement to acquire ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets, which occurred on March 29, 2017, we commenced marketing for sale certain non-core properties. This includes our Grand Rapids project, which is adjacent to our Pelican Lake heavy oil asset. As a result, our Grand Rapids project was reclassified as assets held for sale. The assets are recorded at the lesser of their carrying amount and fair value less costs to sell. The estimated fair value exceeds our carrying value.

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.

Our second quarter results include 45 days of operations from the Deep Basin Assets commencing May 17, 2017. The safe and efficient integration of the Deep Basin Assets is 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 included:

- Netbacks of $9.66 per BOE;
- Total production from the date of acquisition averaging 119,273 BOE per day, equivalent to 58,981 BOE per day for the three months ended June 30, 2017, and 29,654 BOE per day for the six months ended June 30, 2017;
- Revenues of $116 million;
- Total operating costs of $51 million or $8.84 per BOE; and
- Generating Operating Margin net of capital investment of $42 million.

Financial Results

($ millions)	May 17 – June 30, 2017
Gross Sales	**124**
Less: Royalties	**8**
Revenues	**116**
Expenses	
Transportation and Blending	**10**
Operating	**51**
Operating Margin	**55**
Capital Investment	**13**
Operating Margin Net of Related Capital Investment	**42**

Revenues

Price

	May 17 – June 30, 2017
NGLs ($/bbl)	**27.22**
Light and Medium Oil ($/bbl)	**62.29**
Natural Gas ($/mcf)	**2.88**
Total Oil Equivalent ($/BOE)	**21.94**

Our Deep Basin Assets produce a diverse spectrum of products from natural gas, condensate, other NGLs (including, ethane, propane, butane and pentane) and light and medium oil. Our total oil equivalent sales price averaged $21.94 per BOE for the period ending June 30, 2017.

Revenues include $6 million of processing fee revenue related to our interest 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 June 30, 2017	Six Months Ended June 30, 2017
Liquids		
NGLs (barrels per day)	**13,835**	**6,956**
Light and Medium Oil (barrels per day)	**3,059**	**1,538**
	16,894	**8,494**
Natural Gas (MMcf per day)	**253**	**127**
Total Production (BOE/d)	**58,981**	**29,654**
Natural Gas Production (percentage of total)	**71%**	**71%**
Liquids Production (percentage of total)	**29%**	**29%**

Total production from the date of acquisition to June 30, 2017 was 119,273 BOE per day, equivalent to 58,981 BOE per day for the three months ended June 30, 2017, and 29,654 BOE per day for the six months ended June 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 royalty 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 ("PCOS") allowance, which reduces the royalty for the processing of the Crown's portion of natural gas production.

For the three and six months ended June 30, 2017, the effective liquids royalty rate for our Deep Basin properties was 11.7 percent. For the three and six months ended June 30, 2017, the effective natural gas royalty rate for our Deep Basin properties was 4.1 percent.

Expenses

Operating

Primary drivers of our operating expenses from May 17 to June 30, 2017 related to workforce, repairs and maintenance, property tax and lease costs, and electricity. Operating costs were $8.84 per BOE.

Transportation

Transportation costs were $1.96 per BOE and includes charges for the transportation of crude oil, natural gas and NGLs to the sales point.

Netbacks

($/BOE)	May 17 – June 30, 2017
Sales Price	**21.94**
Royalties	**1.45**
Transportation and Blending	**1.96**
Operating Expenses	**8.84**
Production and Mineral Taxes	**0.03**
Netback	**9.66**

Deep Basin – Capital Investment and Drilling Activity

In the Deep Basin, we are taking a disciplined approach to restarting development activities, including the commencement of our drilling program in the second quarter. Our drilling activity will be focused on drilling horizontal production wells targeting liquids rich gas within the Deep Basin corridor.

Future Capital Investment

Upon further review of our capital program following our June 20, 2017 news release, we updated our 2017 guidance.

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. Our 2017 Deep Basin capital investment post May 17, 2017 is forecast to be between $160 million and $180 million.

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 45 days ended June 30, 2017 was $45 million.

CONVENTIONAL (DISCONTINUED OPERATIONS)

We plan to divest our legacy Conventional assets. This includes our Pelican Lake heavy oil assets that use polymer flood and waterflood technology, our Suffield crude oil and natural gas assets in southern Alberta, a CO_2 enhanced oil recovery project at Weyburn, and emerging tight oil assets in the Palliser area of Alberta. As such, our Conventional segment has been classified as a discontinued operation. 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 second quarter of 2017 compared with 2016 include:

- Our average liquids sales price increasing 22 percent to $51.22 per barrel;
- Liquids and natural gas Netbacks, excluding realized risk management activities, of $23.02 per barrel (2016 – $18.06 per barrel) and $1.42 per Mcf (2016 – $0.28 per Mcf), respectively;
- Liquids production averaging 54,958 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 $109 million, an increase of 31 percent.

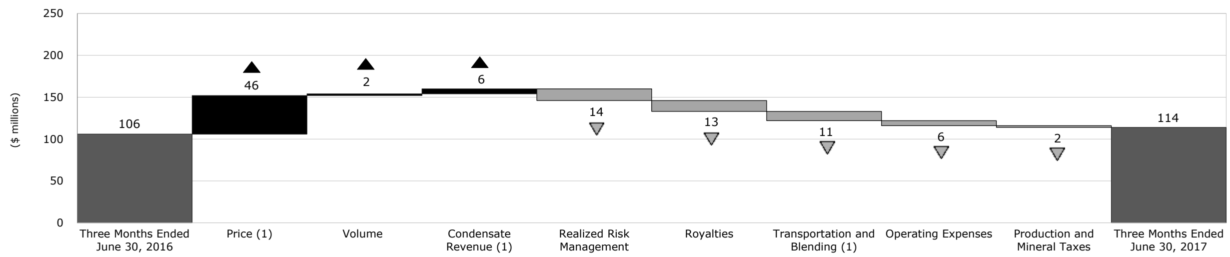
Conventional – Liquids

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

Financial Results

	Three Months Ended June 30,	
($ millions)	**2017**	2016
Gross Sales	**293**	239
Less: Royalties	**44**	31
Revenues	**249**	208
Expenses		
Transportation and Blending	**51**	40
Operating	**76**	70
Production and Mineral Taxes	**5**	3
(Gain) Loss on Risk Management	**3**	(11)
Operating Margin	**114**	106
Capital Investment	**47**	32
Operating Margin Net of Related Capital Investment	**67**	74

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 diverse spectrum 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 $51.22 per barrel in the second quarter of 2017, a 22 percent increase from 2016, due to higher crude oil benchmark prices, adjusted for applicable differentials, the narrowing of the WCS-Condensate differential and the weakening 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

	Three Months Ended June 30,		
(barrels per day)	**2017**	**Percent Change**	2016
Heavy Oil	**26,593**	**(7)%**	28,500
Light and Medium Oil	**27,233**	**4%**	26,177
NGLs	**1,132**	**42%**	799
	54,958	**(1)%**	55,476

Total production declined slightly in 2017 compared with 2016 primarily as a result of expected natural declines. In the second quarter of 2016, production at Pelican Lake was shut down for two days as a safety precaution due to a nearby forest fire, resulting in lost production of approximately 650 barrels per day for the quarter. Light and medium oil increased in 2017 associated with our tight oil drilling program in southern Alberta. NGLs increased compared to 2016 primarily due to improved NGL plant performance.

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 second quarter of 2017, the proportion of the cost of condensate recovered increased.

Royalties

Conventional liquids royalties increased primarily due to higher sales prices. In the second quarter of 2017, the effective liquids royalty rate for our Conventional properties was 18.4 percent (2016 – 15.5 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 for the second quarter of 2016 and 2017.

Expenses

Transportation and Blending

Transportation and blending costs increased in the second quarter of 2017. Blending costs rose primarily due to higher condensate prices. Transportation charges were slightly higher.

Operating

Primary drivers of our operating expenses in the second quarter of 2017 were workforce, workovers, electricity, property taxes and lease costs, and repairs and maintenance. Operating costs increased seven percent to $14.99 per barrel primarily due to:

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

In the second quarter of 2017, production and mineral taxes increased slightly, consistent with the rise in crude oil prices.

Netbacks (1)

	Heavy Oil		Light and Medium Oil	
	Three Months Ended June 30,			
($/bbl)	**2017**	2016	**2017**	2016
Sales Price	**46.67**	36.77	**56.40**	48.09
Royalties	**6.15**	3.95	**11.58**	8.52
Transportation and Blending	**4.48**	3.85	**2.82**	2.77
Operating Expenses	**14.56**	12.34	**16.08**	16.21
Production and Mineral Taxes	**0.01**	0.01	**1.85**	1.18
Netback Excluding Realized Risk Management	**21.47**	16.62	**24.07**	19.41
Realized Risk Management Gain (Loss)	**(0.50)**	2.12	**(0.79)**	2.09
Netback Including Realized Risk Management	**20.97**	18.74	**23.28**	21.50

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

Risk Management

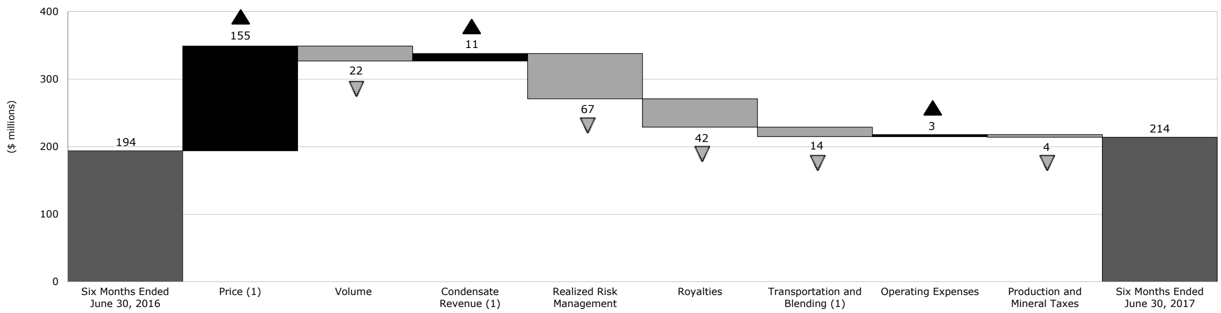
Risk management activities for the second quarter resulted in realized losses of $3 million (2016 – realized gains of $11 million), consistent with average benchmark prices exceeding our contract prices.

Six Months Ended June 30, 2017 Compared With June 30, 2016

Financial Results

	Six Months Ended June 30,	
($ millions)	**2017**	2016
Gross Sales	**572**	428
Less: Royalties	**90**	48
Revenues	**482**	380
Expenses		
Transportation and Blending	**98**	84
Operating	**145**	148
Production and Mineral Taxes	**9**	5
(Gain) Loss on Risk Management	**16**	(51)
Operating Margin	**214**	194
Capital Investment	**132**	69
Operating Margin Net of Related Capital Investment	**82**	125

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 45 percent to $51.65 per barrel consistent with the improvement in crude oil benchmark prices, net of applicable differentials.

Production Volumes

	Six Months Ended June 30,		
(barrels per day)	**2017**	**Percent Change**	2016
Heavy Oil	**26,933**	**(10)%**	29,873
Light and Medium Oil	**26,167**	**(2)%**	26,649
NGLs	**1,090**	**9%**	1,003
	54,190	**(6)%**	57,525

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 and a rise in our NGLs production related to improved NGL plant performance.

Royalties

Royalties increased $42 million primarily due to higher sales prices and lower allowable costs for royalty purposes in Weyburn, partially offset by a reduction in sales volumes. In the first six months of 2017, the effective liquids royalty rate for our Conventional properties was 19.3 percent (2016 – 14.3 percent). The Pelican Lake crown royalty calculation was based on net profits in both 2017 and 2016.

Expenses

Transportation and Blending

Transportation and blending costs increased $14 million. Blending costs rose due to 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 in the first six months of 2017 were workforce costs, workover activities, electricity, property taxes and lease costs, repairs and maintenance, and chemical consumption. Operating expenses increased $0.34 per barrel.

The per unit increase was primarily due to lower production volume and higher energy costs and an increase in workover activities. This increase was partially offset by:

- A decrease in chemical costs associated with reduced polymer consumption;
- Lower property taxes and lease costs;
- A decline in fluid and waste handling and trucking costs; and
- Lower electricity costs as a result of a decline in prices.

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

Netbacks

($/bbl)	Heavy Oil 2017	Heavy Oil 2016	Light and Medium Oil 2017	Light and Medium Oil 2016
	Six Months Ended June 30,			
Sales Price	**47.20**	31.15	**56.61**	41.12
Royalties	**6.57**	2.62	**12.14**	6.82
Transportation and Blending	**3.96**	4.33	**2.76**	2.75
Operating Expenses	**13.74**	13.19	**16.41**	16.28
Production and Mineral Taxes	**0.02**	-	**1.90**	1.00
Netback Excluding Realized Risk Management	**22.91**	11.01	**23.40**	14.27
Realized Risk Management Gain (Loss)	**(1.74)**	5.17	**(1.62)**	5.04
Netback Including Realized Risk Management	**21.17**	16.18	**21.78**	19.31

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

Risk Management

Risk management activities in the first half of the year resulted in realized losses of $16 million (2016 – realized gains of $51 million), consistent with average benchmark prices exceeding our contract prices.

Conventional – Natural Gas

Financial Results

($ millions)	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Gross Sales	**91**	53	**185**	135
Less: Royalties	**6**	2	**10**	5
Revenues	**85**	51	**175**	130
Expenses				
Transportation and Blending	**3**	5	**7**	8
Operating	**37**	36	**78**	78
Production and Mineral Taxes	**-**	-	**1**	-
(Gain) Loss on Risk Management	**-**	-	**-**	1
Operating Margin	**45**	10	**89**	43
Capital Investment	**3**	2	**6**	4
Operating Margin Net of Related Capital Investment	**42**	8	**83**	39

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

Three and Six Months Ended June 30, 2017 Compared With June 30, 2016

Revenues

Price

In the three and six months ended June 30, 2017, our average natural gas sales price increased 84 percent to $2.80 per Mcf and 51 percent to $2.90 per Mcf, respectively. This is consistent with the rise in the AECO benchmark price.

Production

Production decreased seven percent to 355 MMcf per day in the second quarter. On a year-to-date basis, production declined nine percent to 352 MMcf per day due to expected natural declines.

Royalties

Royalties increased as a result of higher prices, partially offset by production declines. The average royalty rate in the second quarter was 5.2 percent (2016 – 4.1 percent) and 5.0 percent (2016 – 4.3 percent) on a year-to-date basis.

Expenses

Transportation

In the three and six months ended June 30, 2017, transportation costs declined slightly compared with 2016 primarily due to the decline in sales volumes.

Operating

Primary drivers of our operating expenses in the three and six months ended June 30, 2017 were property taxes and lease costs, and workforce. Operating expenses increased slightly in the second quarter of 2017 primarily due to an increase in repairs and maintenance. On a year-to-date basis, operating costs remained consistent compared with 2016.

Risk Management

Risk management activities resulted in an impact of $nil in the second quarter and on a year-to-date basis (2016 – $nil in the second quarter and realized losses of $1 million on a year-to-date basis), consistent with average benchmark prices being relatively similar to our contract prices.

Conventional – Capital Investment

($ millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Heavy Oil	**8**	13	**16**	23
Light and Medium Oil	**39**	19	**116**	46
Natural Gas	**3**	2	**6**	4
Capital Investment [(1)]	**50**	34	**138**	73

(1) Includes expenditures on PP&E, E&E assets, and assets classified as discontinued operations.

Capital investment in the first half of 2017 was primarily related to sustaining capital and tight oil development opportunities in southern Alberta. 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

(net wells, unless otherwise stated)	Six Months Ended June 30, 2017	2016
Crude Oil	**23**	1
Recompletions	**-**	65
Gross Stratigraphic Test Wells	**26**	4

Drilling activity in the first six months of 2017 focused on drilling stratigraphic test wells and horizontal production wells for tight oil in southern Alberta.

Future Capital Investment

Our updated 2017 crude oil capital investment forecast is between $225 million and $275 million with spending plans mainly focused on sustaining capital. Guidance has decreased from June 20, 2017 by approximately 23 percent.

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.

Conventional DD&A decreased $74 million in the second quarter of 2017 due to a decline in sales volumes and lower DD&A rates. We stopped recording DD&A on our Pelican Lake and Suffield assets at the end of the first quarter of 2017 due to their held for sale status, as required by IFRS. We stopped recording DD&A on our remaining conventional assets at the end of the second quarter due to our divestiture plans.

DD&A decreased $275 million on a year-to-date basis due to impairment charges of $170 million recorded in the first quarter of 2016 associated with our Northern Alberta cash-generating unit (“CGU”), a decline in sales volumes and the plans to divest of our conventional assets.

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 six months ended June 30, 2017, we loaded an average of 11,079 and 11,482 gross barrels per day, respectively (2016 – 15,531 and 11,122 gross barrels per day, respectively).

Refinery Operations [1]

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	**2017**	2016
Crude Oil Capacity (Mbbls/d)	**460**	460	**460**	460
Crude Oil Runs (Mbbls/d)	**449**	458	**428**	446
Heavy Crude Oil	**201**	228	**201**	235
Light/Medium	**248**	230	**227**	211
Refined Products (Mbbls/d)	**476**	483	**455**	472
Gasoline	**225**	240	**226**	235
Distillate	**154**	150	**143**	146
Other	**97**	93	**86**	91
Crude Utilization (percent)	**98**	100	**93**	97

(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 second quarter, crude oil runs and refined product output declined slightly compared to 2016 primarily due to unplanned maintenance at both Refineries. 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 in the first quarter of 2017. Consistent performance of the Refineries in the second quarter of 2016 was offset by planned and unplanned maintenance at both Refineries in the first quarter of 2016. 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

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Revenues	**2,397**	2,129	**5,001**	3,717
Purchased Product	**2,183**	1,712	**4,513**	3,140
Gross Margin	**214**	417	**488**	577
Expenses				
Operating	**192**	182	**411**	385
(Gain) Loss on Risk Management	**2**	42	**4**	22
Operating Margin	**20**	193	**73**	170
Capital Investment	**40**	53	**86**	105
Operating Margin Net of Related Capital Investment	**(20)**	140	**(13)**	65

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 June 30, 2017, our gross margin declined primarily due to narrowing heavy crude oil differentials, lower average market crack spreads, a decrease in crude utilization rates and a decline in the gross margin from third-party crude oil and natural gas sales undertaken by the marketing group. This was partially offset by the weakening of the Canadian dollar relative to the U.S. dollar in the second quarter compared with 2016, which had a positive impact of approximately $8 million on our refining and marketing gross margin.

In the six months ended June 30, 2017, our gross margin declined primarily due to narrowing heavy crude oil differentials, lower crude utilization rates, decreased margins on the sale of our secondary products due to higher overall feedstock costs, and a decline in the gross margin from third-party crude oil and natural gas sales undertaken by the marketing group.

In the three and six months ended June 30, 2017, the costs associated with Renewable Identification Numbers ("RINs") were $66 million and $127 million, respectively (2016 – $67 million and $129 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 second quarter of 2017 were labour, maintenance, utilities and supplies. On a year-to-date basis, the primary drivers were maintenance, labour, utilities and supplies. Reported operating expenses increased in the second quarter compared with 2016 primarily due to an increase in utility costs resulting from higher natural gas prices and a weakening of the Canadian dollar relative to the U.S. dollar. 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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2017**	2016	**2017**	2016
Wood River Refinery	**22**	38	**56**	75
Borger Refinery	**17**	13	**29**	26
Marketing	**1**	2	**1**	4
	40	53	**86**	105

Capital expenditures in the first half of 2017 focused on capital maintenance and reliability work. Capital investment declined in the three and six months ended June 30, 2017. In the first half of 2016, work continued on the debottlenecking project at the Wood River refinery that was successfully completed in the third quarter of 2016.

In 2017, we expect to invest between $185 million and $215 million mainly related to capital maintenance and reliability work.

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 $5 million in the second quarter and $4 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 second quarter of 2017, our risk management activities resulted in $132 million of unrealized gains (2016 – $284 million of unrealized losses). On a year-to-date basis, we had $411 million of unrealized risk management gains (2016 – $433 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. In the three and six months ended June 30, 2017, we realized $143 million of risk management gains on foreign exchange contracts due to hedging activity undertaken to support the Acquisition.

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
($ millions)	**2017**	2016	**2017**	2016
General and Administrative	**58**	94	**101**	154
Finance Costs	**168**	96	**267**	195
Interest Income	**(10)**	(7)	**(27)**	(18)
Foreign Exchange (Gain) Loss, Net	**(410)**	20	**(486)**	(383)
Revaluation (Gain)	**(2,524)**	-	**(2,524)**	-
Transaction Costs	**26**	-	**55**	-
Re-measurement of the Contingent Payment	**(66)**	-	**(66)**	-
Research Costs	**5**	7	**9**	25
(Gain) Loss on Divestiture of Assets	**-**	1	**1**	1
Other (Income) Loss, Net	**(2)**	2	**(2)**	2
	(2,755)	213	**(2,672)**	(24)

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2017 were workforce and office rent. General and administrative expenses decreased by $36 million in the second quarter and by $53 million on a year-to-date basis. The declines resulted from:

- Lower long-term employee incentive costs related to a drop in our share price;
- A recovery of $3 million in the second quarter and a non-cash expense of $5 million on a year-to-date basis for certain Calgary office space in excess of Cenovus's current and near-term requirements, compared with $17 million and $31 million, respectively, recorded in the three and six months ended June 30, 2016; and
- Lower workforce costs primarily related to $19 million of severance costs recorded in the second quarter of 2016.

These decreases were partially offset by costs related to 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. Costs related to the transitional services were approximately $10 million to date.

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 both the three and six months ended June 30, 2017, finance costs increased $72 million 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 weighted average interest rate on outstanding debt for the three and six months ended June 30, 2017 was 4.8 percent and 5.0 percent, respectively (2016 – 5.3 percent).

Foreign Exchange

	Three Months Ended June 30,		Six Months Ended June 30,	
($ millions)	**2017**	2016	**2017**	2016
Unrealized Foreign Exchange (Gain) Loss	**(396)**	18	**(468)**	(391)
Realized Foreign Exchange (Gain) Loss	**(14)**	2	**(18)**	8
	(410)	20	**(486)**	(383)

Unrealized foreign exchange gains resulted from the translation of our U.S. dollar denominated debt and translation of U.S. cash that was accumulated leading up to the acquisition. The Canadian dollar relative to the U.S. dollar was stronger at June 30, 2017 compared with March 31, 2017, resulting in unrealized gains. The Canadian dollar relative to the U.S. dollar strengthened by three percent at June 30, 2017 compared with December 31, 2016 resulting in year-to-date unrealized gains.

Transaction Costs

In the six months ended June 30, 2017, we expensed $55 million of transaction costs related to the Acquisition. See the Oil Sands and Deep Basin Acquisition section of this MD&A for more details.

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.

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 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 will subsequently be re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. At June 30, 2017, the contingent payment was valued at $295 million and a re-measurement gain of $66 million was recorded. WCS in the second quarter 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$32.25 or C$43.86 per barrel. Our estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$43 per barrel and C$46 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 second quarter was $14 million (2016 – $19 million) and $32 million on a year-to-date basis (2016 – $36 million).

Income Tax

($ millions)	Three Months Ended June 30, **2017**	2016	Six Months Ended June 30, **2017**	2016
Current Tax				
Canada	**(183)**	(59)	**(209)**	(116)
United States	**-**	1	**(1)**	1
Total Current Tax Expense (Recovery)	**(183)**	(58)	**(210)**	(115)
Deferred Tax Expense (Recovery)	**865**	(7)	**941**	(96)
Tax Expense (Recovery) From Continuing Operations	**682**	(65)	**731**	(211)

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

($ millions)	Six Months Ended June 30, **2017**	2016
Earnings (Loss) From Continuing Operations Before Income Tax	**3,523**	(406)
Canadian Statutory Rate	**27.0%**	27.0%
Expected Income Tax (Recovery)	**951**	(110)
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(35)**	(23)
Non-Taxable Capital (Gains) Losses	**(88)**	(53)
Non-Recognition of Capital (Gains) Losses	**(63)**	(53)
Recognition of Previously Unrecognized Capital Losses	**(63)**	-
Non-Deductible Expenses	**10**	5
Other	**19**	23
Total Expense (Recovery) From Continuing Operations	**731**	(211)
Effective Tax Rate	**20.7%**	52.0%

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 six months ended June 30, 2017, a current tax recovery was recorded due to the carry back of current and prior year losses. A deferred tax expense was recorded in the second quarter and on a year-to-date basis in 2017 compared with a recovery in 2016 due to the revaluation gain of our pre-existing partnership interest in connection with the Acquisition and an increase in unrealized gains on risk management activities.

In the three and six months ended June 30, 2017, we recorded income tax of $20 million related to discontinued operations (three and six months ended June 30, 2016 – $16 million and $87 million income tax recovery, respectively).

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended June 30, 2017	2016	Six Months Ended June 30, 2017	2016
Cash From (Used In)				
Operating Activities	**1,239**	205	**1,567**	387
Investing Activities	**(14,706)**	(270)	**(15,165)**	(639)
Net Cash Provided (Used) Before Financing Activities	**(13,467)**	(65)	**(13,598)**	(252)
Financing Activities	**10,288**	(43)	**10,236**	(84)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**120**	5	**131**	11
Increase (Decrease) in Cash and Cash Equivalents	**(3,059)**	(103)	**(3,231)**	(325)

	June 30, 2017	December 31, 2016
Cash and Cash Equivalents	**489**	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 six months ended June 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 contingent payment we had a working capital of $15 million at June 30, 2017 compared with a surplus of $4,423 million at December 31, 2016. The change 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 three and six months ended June 30, 2017, the change in Cash Used In Investing Activities was primarily due to the Acquisition. Capital investment increased in the current quarter and on a year-to-date basis. 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 From Financing Activities increased in the second quarter of 2017 and on a year-to-date basis primarily related to the issuance of debt and common shares to help finance the Acquisition.

Total debt, including the current portion as at June 30, 2017 was $13,413 million (December 31, 2016 – $6,332 million), which includes $9,927 million of U.S. denominated senior unsecured notes with no principal payments due until October 15, 2019 (US$1.3 billion) and $3.6 billion under a committed Bridge Facility, both amounts are partially offset by debt discount and transaction costs. The $7,081 million increase in total debt is primarily due to Acquisition financing through the offering for US$2.9 billion of senior unsecured notes and the committed Bridge Facility. The current portion of the committed Bridge Facility is $893 million and it matures May 17, 2018.

As at June 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, Cenovus completed an offering in the United States 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.

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 consists 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. As at June 30, 2017, $3.6 billion remained outstanding on our committed Bridge Facility. We expect to repay the committed Bridge Facility through the sale of assets. See the Oil Sands and Deep Basin Acquisition section of this MD&A for more details.

Dividends

In the three and six months ended June 30, 2017, we paid dividends of $0.05 per share or $61 million and $0.10 per share or $102 million, respectively (2016 – $0.05 per share or $42 million and $0.10 per share or $83 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 June 30, 2017:

($ billions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**0.5**
Committed Credit Facility – Tranche A	**November 2021**	**3.3**
Committed Credit Facility – Tranche B	**November 2020**	**1.2**
Base Shelf Prospectus [(1)]	**March 2018**	**US$2.8**

(1) Availability is subject to market conditions. See below and the Oil Sands and Deep Basin Acquisition section of this MD&A for details related to the Acquisition.

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 June 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.

Base Shelf Prospectus

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

In connection with the Acquisition, on April 6, 2017, Cenovus closed a Bought-Deal Common Share Offering for 187.5 million common shares under the base shelf prospectus for gross proceeds of $3.0 billion. As at June 30, 2017, US$2.8 billion remains available under the base shelf prospectus. See the Oil Sands and Deep Basin Acquisition section of this MD&A for more details.

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 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	**June 30, 2017**	December 31, 2016
Net Debt to Capitalization [(1)] [(2)]	**40%**	18%
Debt to Capitalization	**41%**	35%
Net Debt to Adjusted EBITDA [(1)]	**6.1x**	1.9x
Debt to Adjusted EBITDA	**6.4x**	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 the higher long-term debt balance, related to the Acquisition and the weakening of the Canadian dollar relative to the U.S. dollar, partially offset by the increase in Shareholders' Equity. Debt to Adjusted EBITDA increased as a result of a higher long-term debt balance, partially offset by a higher Adjusted EBITDA from an increase in commodity prices and the rise in sales volumes as a result of the Acquisition. We are intently focused on completing divestitures of our legacy Conventional assets in order to deleverage our balance sheet.

As at June 30, 2017, Cenovus's Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA are 6.4x and 6.1x, 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 June 30, 2017. Debt and Net Debt are as at June 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 June 30, 2017 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 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 June 30, 2017	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**44,164**	**37,096**
Other Stock-Based Compensation Plans	**14,581**	**1,613**

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 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 June 30, 2017, total commitments were $29.9 billion, of which $26.4 billion were for various transportation commitments. During the six months ended June 30, 2017, in relation to the Acquisition, Cenovus assumed commitments of $3.7 billion, primarily consisting of transportation commitments on various pipelines primarily related to FCCL. This increase in commitments was offset by our withdrawal from certain transportation initiatives and use of contracts. Transportation commitments include $16 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2016 – $19 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 June 30, 2017, there were outstanding letters of credit aggregating $246 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 June 30, 2017, the estimated fair value of the contingent payment was $295 million. WCS in the second quarter 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 Oil Sands and Deep Basin Acquisition and 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 quarter 2017 MD&A. 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 and AIF.

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

Commodity Price Risk

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 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

	Three Months Ended June 30,					
	2017			2016		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [1]	**(14)**	**(166)**	**(180)**	19	246	265
Refining	**2**	**(3)**	**(1)**	(1)	1	-
Interest Rate	**-**	**13**	**13**	-	37	37
Foreign Exchange	**(143)**	**24**	**(119)**	-	-	-
(Gain) Loss on Risk Management	**(155)**	**(132)**	**(287)**	18	284	302
Income Tax Expense (Recovery)	**39**	**37**	**76**	(6)	(77)	(83)
(Gain) Loss on Risk Management, After Tax	**(116)**	**(95)**	**(211)**	12	207	219

(1) *Excludes $3 million of realized risk management losses on crude oil contracts from our Conventional segment (2016 – $11 million realized risk management gains), which has been classified as a discontinued operation.*

Impact of Financial Risk Management Activities

	Six Months Ended June 30,					
	2017			2016		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [1]	**63**	**(417)**	**(354)**	(106)	364	258
Refining	**4**	**(3)**	**1**	(5)	4	(1)
Power	**-**	**-**	**-**	3	(14)	(11)
Interest Rate	**-**	**9**	**9**	-	79	79
Foreign Exchange	**(143)**	**-**	**(143)**	-	-	-
(Gain) Loss on Risk Management	**(76)**	**(411)**	**(487)**	(108)	433	325
Income Tax Expense (Recovery)	**18**	**112**	**130**	28	(118)	(90)
(Gain) Loss on Risk Management, After Tax	**(58)**	**(299)**	**(357)**	(80)	315	235

(1) *Excludes $16 million of realized risk management losses on crude oil contracts from our Conventional segment (2016 – $50 million realized risk management gains), which has been classified as a discontinued operation.*

In the second quarter of 2017 and on a year-to-date basis, we incurred realized gains on foreign exchange contracts due to hedging activity undertaken to support the Acquisition. In the second quarter of 2017, we incurred realized gains on crude oil risk management activities, consistent with our contract prices exceeding the average benchmark prices. In the first half of 2017, we recorded realized losses on crude oil risk management activities as average benchmark prices exceeded our contract prices. Unrealized gains were recorded on our crude oil financial instruments in the three and six months ended June 30, 2017 primarily due to the realization of settled positions and changes in market prices.

Risks Related to the Acquisition

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 existing committed credit facility and a 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 existing committed credit facility or 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 will represent a significant increase in Cenovus's consolidated indebtedness. Such additional indebtedness will increase Cenovus's interest expense and debt service obligations and may have a negative effect on Cenovus's results of operations.

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.

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 June 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 first six months of 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 six months ended June 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 for the period ended June 30, 2017. 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 a modified retrospective 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

Management has assessed changes to its control environment related to the Acquisition. There have been no changes to internal control over financial reporting during the three months ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect internal control over financial reporting.

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 has increased our interest in FCCL to 100 percent and provided us with a second growth platform of Deep Basin Assets in Alberta and British Columbia. We are also currently marketing for sale our legacy Conventional oil and natural gas assets.

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.

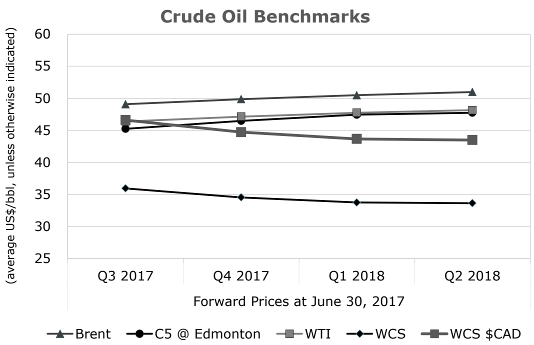
We have reduced the amount of capital needed to sustain our base business and expand our projects, which we expect will allow us to reactivate growth in a disciplined manner. We believe these efforts will help to ensure our financial resilience.

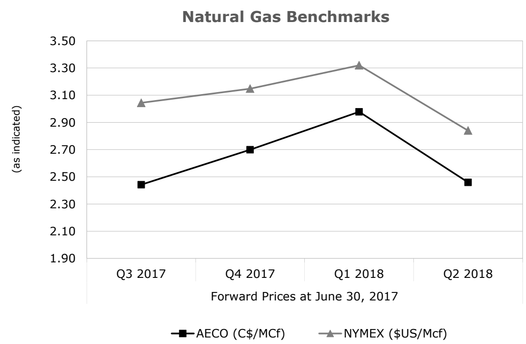
The following outlook commentary is focused on the next 12 months.

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 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 second half of 2017. OPEC’s ability to adhere to its production cuts combined with annual increases in demand growth should support prices in the remainder of the year, constrained by the need to draw down surplus crude oil inventories and U.S. production growth;
- We anticipate the Brent-WTI differential to remain narrow now that the U.S. is exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and
- We expect that the WTI-WCS differential will widen due to Canadian supply returning from production outages, oil sands supply growth, and potential transportation constraints.

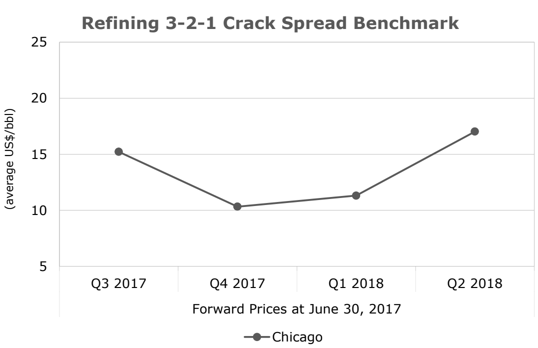


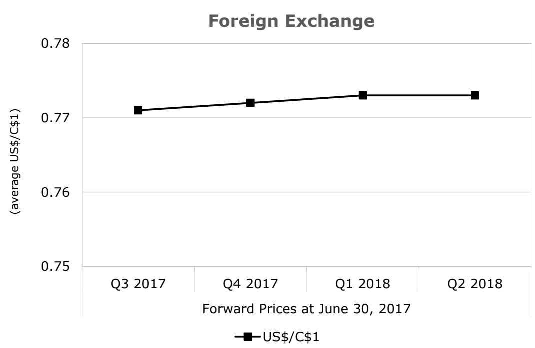


Natural gas pricing is anticipated to improve throughout the second half of 2017 as we expect strong structural demand growth and only a slight increase in natural gas production. However, higher prices will likely be limited by the ability of the power sector to use coal as a substitute for natural gas.

U.S. refining crack spreads are expected to weaken in the second half of the year as high global refined product inventories continue to weigh on product prices while seasonal U.S. demand weakens during fall and winter periods. The impact of weaker refining crack spreads will be partially offset by the widening of the WTI-WCS differential, creating a feedstock cost advantage.

We expect the Canadian dollar to continue to be tied with a modest improvement in crude oil prices and the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise interest rates. The Bank of Canada has recently raised its benchmark rate for the first time in nearly seven years marking a notable shift for Canada towards 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 on track. We are targeting between $4.0 billion and $5.0 billion 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 June 30, 2017, through a combination of cash and $4.5 billion available under our committed credit facility, we have approximately $5.0 billion dollars 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

We updated our 2017 capital investment guidance and anticipate capital investment to be between $1.6 billion and $1.8 billion. Guidance has decreased from June 20, 2017 by approximately 11 percent.

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 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 and sustain 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; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and NGLs from properties and other sources not currently classified as proved; future use and development of technology; 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; our ability to generate sufficient cash flow to meet our current and future obligations; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2017 guidance, as updated July 26, 2017, assumes: Brent prices of US$51.00/bbl, WTI prices of US$48.50/bbl; WCS of US$36.25/bbl; NYMEX natural gas prices of US$3.15/MMBtu; AECO natural gas prices of $2.70/GJ; Chicago 3-2-1 crack spread of US$13.00/bbl; and an exchange rate of $0.76 US$/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
bbls/d	barrels per day	MMcf	million cubic feet
Mbbls/d	thousand barrels per day	Bcf	billion cubic feet
MMbbls	million barrels	MMBtu	million British thermal units
BOE	barrel of oil equivalent	GJ	gigajoule
BOE/d	barrel of oil equivalent per day	AECO	Alberta Energy Company
MBOE	thousand barrel of oil equivalent	NYMEX	New York Mercantile Exchange
MMBOE	million barrel of oil equivalent		
WTI	West Texas Intermediate		
WCS	Western Canadian Select		
CDB	Christina Dilbit Blend	TM	trademark of Cenovus Energy Inc.

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 June 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	**1,666**	**124**	**386**	**2,176**
Less: Royalties	**36**	**8**	**50**	**94**
	1,630	**116**	**336**	**2,082**
Expenses				
Transportation and Blending	**879**	**10**	**54**	**943**
Operating	**221**	**51**	**115**	**387**
Production and Mineral Taxes	**-**	**-**	**5**	**5**
Netback	**530**	**55**	**162**	**747**
(Gain) Loss on Risk Management	**(14)**	**-**	**3**	**(11)**
Operating Margin	**544**	**55**	**159**	**758**

Three Months Ended June 30, 2016 ($ millions)	Per Interim Consolidated Financial Statements Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	**709**	**-**	**294**	**1,003**
Less: Royalties	**3**	**-**	**33**	**36**
	706	**-**	**261**	**967**
Expenses				
Transportation and Blending	**395**	**-**	**45**	**440**
Operating	**104**	**-**	**107**	**211**
Production and Mineral Taxes	**-**	**-**	**3**	**3**
Netback	**207**	**-**	**106**	**313**
(Gain) Loss on Risk Management	**(24)**	**-**	**(11)**	**(35)**
Operating Margin	**231**	**-**	**117**	**348**

(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 June 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Condensate	Inventory	Other	Per Above Table Total Upstream
Revenues					
Gross Sales	**1,416**	**751**	**-**	**9**	**2,176**
Less: Royalties	**93**	**-**	**-**	**1**	**94**
	1,323	**751**	**-**	**8**	**2,082**
Expenses					
Transportation and Blending	**189**	**751**	**-**	**3**	**943**
Operating	**380**	**-**	**-**	**7**	**387**
Production and Mineral Taxes	**5**	**-**	**-**	**-**	**5**
Netback	**749**	**-**	**-**	**(2)**	**747**
(Gain) Loss on Risk Management	**(11)**	**-**	**-**	**-**	**(11)**
Operating Margin	**760**	**-**	**-**	**(2)**	**758**

Three Months Ended June 30, 2016 ($ millions)	Basis of Netback Calculation Total	Adjustments Condensate	Inventory	Other	Per Above Table Total Upstream
Revenues					
Gross Sales	**652**	**349**	**-**	**2**	**1,003**
Less: Royalties	**36**	**-**	**-**	**-**	**36**
	616	**349**	**-**	**2**	**967**
Expenses					
Transportation and Blending	**120**	**349**	**(29)**	**-**	**440**
Operating	**209**	**-**	**-**	**2**	**211**
Production and Mineral Taxes	**3**	**-**	**-**	**-**	**3**
Netback	**284**	**-**	**29**	**-**	**313**
(Gain) Loss on Risk Management	**(35)**	**-**	**-**	**-**	**(35)**
Operating Margin	**319**	**-**	**29**	**-**	**348**

Total Production

Upstream Financial Results

Six Months Ended June 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	**2,728**	**124**	**760**	**3,612**
Less: Royalties	**63**	**8**	**100**	**171**
	2,665	**116**	**660**	**3,441**
Expenses				
Transportation and Blending	**1,445**	**10**	**105**	**1,560**
Operating	**361**	**51**	**225**	**637**
Production and Mineral Taxes	**-**	**-**	**10**	**10**
Netback	**859**	**55**	**320**	**1,234**
(Gain) Loss on Risk Management	**63**	**-**	**16**	**79**
Operating Margin	**796**	**55**	**304**	**1,155**

Six Months Ended June 30, 2016 ($ millions)	Per Interim Consolidated Financial Statements Oil Sands [1]	Deep Basin [1]	Conventional [2]	Total Upstream
Revenues				
Gross Sales	1,179	-	568	1,747
Less: Royalties	3	-	53	56
	1,176	-	515	1,691
Expenses				
Transportation and Blending	799	-	92	891
Operating	231	-	229	460
Production and Mineral Taxes	-	-	5	5
Netback	146	-	189	335
(Gain) Loss on Risk Management	(130)	-	(50)	(180)
Operating Margin	276	-	239	515

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

Netback Reconciliations

Six Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Condensate	Inventory	Other	Per Above Table Total Upstream
Revenues					
Gross Sales	**2,336**	**1,262**	**-**	**14**	**3,612**
Less: Royalties	**170**	**-**	**-**	**1**	**171**
	2,166	**1,262**	**-**	**13**	**3,441**
Expenses					
Transportation and Blending	**295**	**1,262**	**1**	**2**	**1,560**
Operating	**629**	**-**	**-**	**8**	**637**
Production and Mineral Taxes	**10**	**-**	**-**	**-**	**10**
Netback	**1,232**	**-**	**(1)**	**3**	**1,234**
(Gain) Loss on Risk Management	**79**	**-**	**-**	**-**	**79**
Operating Margin	**1,153**	**-**	**(1)**	**3**	**1,155**

Six Months Ended June 30, 2016 ($ millions)	Basis of Netback Calculation Total	Adjustments Condensate	Inventory	Other	Per Above Table Total Upstream
Revenues					
Gross Sales	1,028	712	-	7	1,747
Less: Royalties	56	-	-	-	56
	972	712	-	7	1,691
Expenses					
Transportation and Blending	230	712	(51)	-	891
Operating	457	-	-	3	460
Production and Mineral Taxes	5	-	-	-	5
Netback	280	-	51	4	335
(Gain) Loss on Risk Management	(183)	-	-	3	(180)
Operating Margin	463	-	51	1	515

Oil Sands

Three Months Ended June 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	429	514	943	4	719	-	-	1,666
Less: Royalties	24	12	36	-	-	-	-	36
	405	502	907	4	719	-	-	1,630
Expenses								
Transportation and Blending	100	58	158	-	719	-	2	879
Operating	119	99	218	2	-	-	1	221
Netback	186	345	531	2	-	-	(3)	530
(Gain) Loss on Risk Management	(9)	(5)	(14)	-	-	-	-	(14)
Operating Margin	195	350	545	2	-	-	(3)	544

Three Months Ended June 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	189	196	385	2	322	-	-	709
Less: Royalties	1	2	3	-	-	-	-	3
	188	194	382	2	322	-	-	706
Expenses								
Transportation and Blending	65	34	99	-	322	(26)	-	395
Operating	57	44	101	2	-	-	1	104
Netback	66	116	182	-	-	26	(1)	207
(Gain) Loss on Risk Management	(11)	(13)	(24)	-	-	-	-	(24)
Operating Margin	77	129	206	-	-	26	(1)	231

Six Months Ended June 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	716	804	1,520	6	1,197	-	5	2,728
Less: Royalties	44	19	63	-	-	-	-	63
	672	785	1,457	6	1,197	-	5	2,665
Expenses								
Transportation and Blending	155	91	246	-	1,197	1	1	1,445
Operating	190	164	354	5	-	-	2	361
Netback	327	530	857	1	-	(1)	2	859
(Gain) Loss on Risk Management	31	32	63	-	-	-	-	63
Operating Margin	296	498	794	1	-	(1)	2	796

Six Months Ended June 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	254	261	515	6	657	-	1	1,179
Less: Royalties	1	2	3	-	-	-	-	3
	253	259	512	6	657	-	1	1,176
Expenses								
Transportation and Blending	113	73	186	-	657	(44)	-	799
Operating	124	99	223	5	-	-	3	231
Netback	16	87	103	1	-	44	(2)	146
(Gain) Loss on Risk Management	(63)	(67)	(130)	-	-	-	-	(130)
Operating Margin	79	154	233	1	-	44	(2)	276

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

Deep Basin

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements [1] Total Deep Basin
Revenues			
Gross Sales	**118**	**6**	**124**
Less: Royalties	**8**	**-**	**8**
	110	**6**	**116**
Expenses			
Transportation and Blending	**10**	**-**	**10**
Operating	**47**	**4**	**51**
Production and Mineral Taxes	**-**	**-**	**-**
Netback	**53**	**2**	**55**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**53**	**2**	**55**

Six Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements [1] Total Deep Basin
Revenues			
Gross Sales	**118**	**6**	**124**
Less: Royalties	**8**	**-**	**8**
	110	**6**	**116**
Expenses			
Transportation and Blending	**10**	**-**	**10**
Operating	**47**	**4**	**51**
Production and Mineral Taxes	**-**	**-**	**-**
Netback	**53**	**2**	**55**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**53**	**2**	**55**

(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 June 30, 2017 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Revenues										
Gross Sales	**119**	**138**	**4**	**261**	**90**	**351**	**32**	**-**	**3**	**386**
Less: Royalties	**16**	**28**	**-**	**44**	**5**	**49**	**-**	**-**	**1**	**50**
	103	**110**	**4**	**217**	**85**	**302**	**32**	**-**	**2**	**336**
Expenses										
Transportation and Blending	**11**	**7**	**-**	**18**	**3**	**21**	**32**	**-**	**1**	**54**
Operating	**37**	**39**	**-**	**76**	**37**	**113**	**-**	**-**	**2**	**115**
Production and Mineral Taxes	**-**	**5**	**-**	**5**	**-**	**5**	**-**	**-**	**-**	**5**
Netback	**55**	**59**	**4**	**118**	**45**	**163**	**-**	**-**	**(1)**	**162**
(Gain) Loss on Risk Management	**2**	**1**	**-**	**3**	**-**	**3**	**-**	**-**	**-**	**3**
Operating Margin	**53**	**58**	**4**	**115**	**45**	**160**	**-**	**-**	**(1)**	**159**

	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements [1]
Three Months Ended June 30, 2016 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Revenues										
Gross Sales	95	116	1	212	53	265	27	-	2	294
Less: Royalties	10	20	1	31	2	33	-	-	-	33
	85	96	-	181	51	232	27	-	2	261
Expenses										
Transportation and Blending	10	6	-	16	5	21	27	(3)	-	45
Operating	31	39	-	70	36	106	-	-	1	107
Production and Mineral Taxes	-	3	-	3	-	3	-	-	-	3
Netback	44	48	-	92	10	102	-	3	1	106
(Gain) Loss on Risk Management	(5)	(6)	-	(11)	-	(11)	-	-	-	(11)
Operating Margin	49	54	-	103	10	113	-	3	1	117

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

Conventional

Six Months Ended June 30, 2017 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[1]
Revenues										
Gross Sales	**232**	**266**	**9**	**507**	**185**	**692**	**65**	**-**	**3**	**760**
Less: Royalties	**32**	**57**	**1**	**90**	**9**	**99**	**-**	**-**	**1**	**100**
	200	**209**	**8**	**417**	**176**	**593**	**65**	**-**	**2**	**660**
Expenses										
Transportation and Blending	**19**	**13**	**-**	**32**	**7**	**39**	**65**	**-**	**1**	**105**
Operating	**68**	**77**	**-**	**145**	**78**	**223**	**-**	**-**	**2**	**225**
Production and Mineral Taxes	**-**	**9**	**-**	**9**	**1**	**10**	**-**	**-**	**-**	**10**
Netback	**113**	**110**	**8**	**231**	**90**	**321**	**-**	**-**	**(1)**	**320**
(Gain) Loss on Risk Management	**9**	**7**	**-**	**16**	**-**	**16**	**-**	**-**	**-**	**16**
Operating Margin	**104**	**103**	**8**	**215**	**90**	**305**	**-**	**-**	**(1)**	**304**

Six Months Ended June 30, 2016 ($ millions)	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[1]
Revenues										
Gross Sales	168	201	4	373	135	508	55	-	5	568
Less: Royalties	14	33	1	48	5	53	-	-	-	53
	154	168	3	325	130	455	55	-	5	515
Expenses										
Transportation and Blending	23	13	-	36	8	44	55	(7)	-	92
Operating	71	79	-	150	78	228	-	-	1	229
Production and Mineral Taxes	-	5	-	5	-	5	-	-	-	5
Netback	60	71	3	134	44	178	-	7	4	189
(Gain) Loss on Risk Management	(27)	(26)	-	(53)	1	(52)	-	-	2	(50)
Operating Margin	87	97	3	187	43	230	-	7	2	239

(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 June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
Oil Sands				
Foster Creek	**106,115**	62,089	**92,415**	61,129
Christina Lake	**154,431**	76,066	**122,353**	78,092
Total Oil Sands Crude Oil	**260,546**	138,155	**214,768**	139,221
Natural Gas (MMcf per day)	**12**	18	**13**	17
Deep Basin				
Total Liquids	**16,894**	-	**8,494**	-
Natural Gas (MMcf per day)	**253**	-	**127**	-
Conventional				
Heavy Oil	**28,089**	28,294	**27,161**	29,529
Light and Medium Oil	**26,835**	26,407	**25,959**	26,808
Natural Gas Liquids ("NGLs")	**1,132**	799	**1,090**	1,003
Total Conventional Liquids	**56,056**	55,500	**54,210**	57,340
Natural Gas (MMcf per day)	**355**	381	**352**	386
Total Liquids Sales	**333,496**	193,655	**277,472**	196,561
Total Sales (BOE per day)	**436,761**	260,155	**359,465**	263,728