MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED MARCH 31, 2018

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated April 24, 2018, should be read in conjunction with our March 31, 2018 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2017 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2017 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 24, 2018, unless otherwise indicated. This MD&A provides an update to our annual MD&A and contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The interim MD&As are approved by the Audit Committee of the Cenovus Board of Directors (the "Board") and the annual MD&A is reviewed by the Audit Committee and recommended for its approval by the Board. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the interim Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, except where another currency has been indicated, and in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") as issued by the International Accounting Standards Board ("IASB"). Production volumes are presented on a before royalties basis.

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Debt, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Notes 1 and 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 Operating Results, Financial 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 March 31, 2018, we had an enterprise value of approximately $23 billion. Operations include oil sands projects in northern Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Our average crude oil and NGLs (collectively, "liquids") production for the three months ended March 31, 2018 was 395,145 barrels per day, our average natural gas production was 553 MMcf per day, and our total production from continuing operations was 487,464 BOE per day. We also conduct marketing activities and have refining operations in the United States ("U.S."). The refining operations processed an average of 349,000 gross barrels per day of crude oil feedstock into an average of 369,000 gross barrels per day of refined products.

Our strategy is to increase cash flows through disciplined production growth from our industry-leading portfolio of oil sands and Deep Basin natural gas and liquids assets in western Canada. We are focused on increasing our current share price and maximizing shareholder value through cost leadership and realizing the best margins for our products to help us maintain financial resilience and deliver sustainable dividend growth. We plan to achieve our strategy by drawing on the expertise of our people and leveraging our premium asset quality, executional excellence, value-added integration, focused innovation and trusted reputation.

Our Operations

Oil Sands

Our oil sands assets include steam-assisted gravity drainage ("SAGD") oil sands projects in northern Alberta, including Foster Creek, Christina Lake, Narrows Lake and other emerging projects. Foster Creek and Christina Lake are producing, while Narrows Lake is in the initial stages of development. These three projects are located in the Athabasca region of northeastern Alberta and our project at Telephone Lake is located within the Borealis region of northeastern Alberta. The Oil Sands segment also includes the Athabasca natural gas property, from which a portion of the natural gas production is used as fuel at the adjacent Foster Creek operations.

Deep Basin

Our Deep Basin operations include liquids rich natural gas, condensate and other NGLs, and light and medium oil assets located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities (collectively, the "Deep Basin Assets"). The Deep Basin Assets provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. A portion of the natural gas produced is used as fuel in our oil sands operations and provides an economic hedge for the natural gas required as a fuel source at our refining operations.

Refining and Marketing

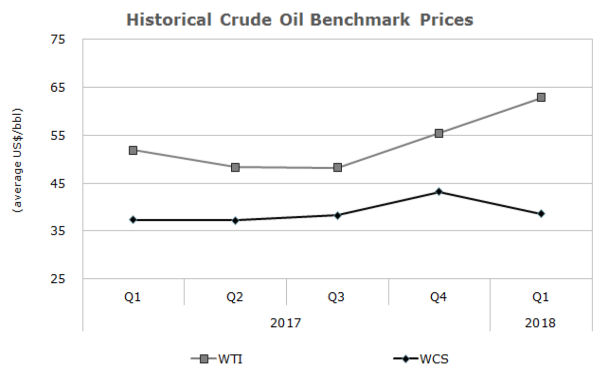
Our operations include two refineries located in Illinois and Texas that are jointly owned with (50 percent interest) and operated by Phillips 66, an unrelated U.S. public company. The gross crude oil capacity at the Wood River and Borger refineries (the "Refineries") is approximately 314,000 barrels per day and 146,000 barrels per day, respectively. This includes processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations.

This segment also includes our crude-by-rail terminal operations, located in Bruderheim, Alberta, and the marketing of third-party purchases and sales of product undertaken to provide operational flexibility for transportation commitments, product quality, delivery points and customer diversification.

Operating Margin Net of Related Capital Investment

	Three Months Ended March 31, 2018		
($ millions)	Oil Sands	Deep Basin	Refining and Marketing
Operating Margin	106	99	(48)
Capital Investment	318	145	53
Operating Margin Net of Related Capital Investment	(212)	(46)	(101)

QUARTERLY HIGHLIGHTS



Market conditions in the quarter saw light oil and condensate benchmark prices increase compared with the first quarter of 2017, while at the same time, light-heavy crude oil price differentials increased significantly, leaving heavy crude oil benchmark prices relatively unchanged year over year. The differential between West Texas Intermediate ("WTI") and Western Canadian Select ("WCS") prices averaged US$24.28 per barrel (39 percent of WTI) in the quarter, a level not seen since the fourth quarter of 2013, and a 67 percent increase compared with the same period in 2017. The widening of the differential was a result of market access constraints and increasing heavy oil production in Alberta.

In response to limited takeaway capacity and discounted heavy oil pricing, we operated our Christina Lake and Foster Creek facilities at reduced production levels in February and March, using the significant storage capacity in our oil sands reservoirs which provides us flexibility on timing of production and sales of our inventory as pipeline capacity improves and crude oil differentials narrow.

In the first quarter of 2018, we:

- Produced 487,464 BOE per day from continuing operations, a significant increase from the first quarter of 2017 due to the acquisition from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") of the remaining 50 percent interest in the FCCL Partnership ("FCCL") and the Deep Basin Assets on May 17, 2017 ("the Acquisition");
- Earned an average companywide Netback from continuing operations of $16.80 per BOE, before realized hedging, down 21 percent from the first quarter of 2017 primarily due to the impact of higher condensate costs and materially wider light-heavy crude oil differentials resulting in weaker realized sales prices for our barrels;
- Incurred realized risk management losses of $469 million largely as a result of hedging contracts established to provide downside protection following the Acquisition to support financial resilience;
- Substantially completed major planned turnaround activity at the Wood River and Borger refineries;
- Recorded a Net Loss from continuing operations of $914 million (2017 – Net Earnings of $211 million);
- Recorded Adjusted Funds Flow of negative $41 million compared with Adjusted Funds Flow of $323 million in 2017;
- Invested $524 million in capital compared with $313 million in 2017, reflecting our increased ownership in FCCL and the new asset base in the Deep Basin as a result of the Acquisition;
- Recorded an impairment of $100 million on our Clearwater assets due to declining forward natural gas prices;
- Closed the sale of our Suffield divestiture for gross cash proceeds of $512 million, before closing adjustments, and a before-tax gain of $348 million; and
- Substantially completed previously announced workforce reductions of approximately 15 percent from 2017 levels.

OPERATING RESULTS

Total production of 488,561 BOE per day increased relative to the first quarter of 2017 primarily due to the Acquisition, offset by the disposition of our legacy Conventional assets late in the second half of 2017. In addition, production at our oil sands facilities was impacted by the decision to reduce production and leave barrels not yet produced in our reservoirs in February and March due to pipeline capacity constraints and wider light-heavy oil price differentials.

Production Volumes

	Three Months Ended March 31,		
	2018	**Percent Change**	2017
Continuing Operations			
Liquids (barrels per day)			
Oil Sands			
Foster Creek	**157,390**	**95**	80,866
Christina Lake	**202,276**	**101**	100,635
	359,666	**98**	181,501
Deep Basin			
Crude Oil	**6,517**	**-**	-
NGLs	**28,962**	**-**	-
	35,479	**-**	-
Liquids Production (barrels per day)	**395,145**	**118**	181,501
Natural Gas (MMcf per day)			
Oil Sands	**4**	**(73)**	15
Deep Basin [(1)]	**549**	**-**	-
	553	**3,587**	15
Production From Continuing Operations (BOE per day)	**487,464**	**165**	184,001
Production From Discontinued Operations (Conventional) (BOE per day)	**1,097**	**(99)**	111,413
Total Production (BOE per day)	**488,561**	**65**	295,414

(1) Includes production used for internal consumption by the Oil Sands segment of 322 MMcf/d.

Oil Sands production averaged 359,666 barrels per day in the quarter, a significant increase compared with last year, primarily due to the Acquisition.

Total production from the Deep Basin Assets, acquired on May 17, 2017, averaged 127,056 BOE per day in the first quarter of 2018, with 17 horizontal wells being brought on production.

Production in 2018 from our Conventional segment reflects the results of our Suffield operations, which were sold on January 5, 2018. All references to our legacy Conventional segment are accounted for as a discontinued operation.

Netbacks From Continuing Operations

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, and is defined in the Canadian Oil and Gas Evaluation Handbook. 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 writedowns 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 March 31,	
($/BOE)	**2018**	2017
Sales Price	**33.20**	37.77
Royalties	**2.34**	1.76
Transportation and Blending	**6.16**	5.73
Operating Expenses	**7.89**	9.03
Production and Mineral Taxes	**0.01**	-
Netback Excluding Realized Risk Management (1) (2)	**16.80**	21.25
Realized Risk Management Gain (Loss)	**(11.69)**	(5.01)
Netback Including Realized Risk Management (1) (2)	**5.11**	16.24

(1) Excludes results from our Conventional segment, which has been classified as a discontinued operation.
(2) Excludes intersegment sales.

Our average Netback decreased relative to the first quarter of 2017 primarily due to the impact of materially wider light-heavy crude oil price differentials, higher condensate costs, lower natural gas prices and realized risk management losses as a result of crude prices exceeding our contract prices. WCS as a percentage of WTI was 61 percent in 2018 compared with 72 percent in the same period of 2017, reflecting a decrease in heavy crude oil sales price realizations relative to WTI benchmark pricing. In addition, as the cost of condensate increases relative to the price of blended crude oil, our bitumen sales price decreases. Our average sales price was also effected by the strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact on our sales price of approximately $1.54 per BOE. The impact of higher royalties, and transportation and blending costs were offset by the decline in operating costs.

Refining and Marketing

Crude oil runs and refined product output in the first three months of 2018 decreased compared with 2017. In the first quarter of 2018, major planned turnarounds were substantially completed at both the Wood River and Borger refineries. In the first quarter of 2017, the Refineries were impacted by smaller-scale planned turnarounds.

	Three Months Ended March 31,		
	2018	**Percent Change**	2017
Crude Oil Runs (1) (Mbbls/d)	**349**	**(14)**	406
Heavy Crude Oil (1)	**162**	**(19)**	200
Refined Product (1) (Mbbls/d)	**369**	**(15)**	433
Crude Utilization (1) (percent)	**76**	**(12)**	88

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

In 2018, Operating Margin from our Refining and Marketing segment decreased relative to the first quarter of 2017 as higher operating costs and lower crude utilization due to the planned turnarounds at both refineries offset higher average market crack spreads and wider light-heavy crude oil differentials, which decreases input costs to the Refineries.

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 and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [(1)]

(US$/bbl, unless otherwise indicated)	Q1 2018	Percent Change	Q1 2017	Q4 2017
Brent				
Average	**67.18**	**23**	54.66	61.54
End of Period	**70.27**	**33**	52.83	66.87
WTI				
Average	**62.87**	**21**	51.91	55.40
End of Period	**64.94**	**28**	50.60	60.42
Average Differential Brent-WTI	**4.31**	**57**	2.75	6.14
WCS				
Average	**38.59**	**3**	37.33	43.14
Average (C$/bbl)	**48.79**	**(1)**	49.38	54.84
End of Period	**42.88**	**8**	39.77	34.93
Average Differential WTI-WCS	**24.28**	**67**	14.58	12.26
Condensate (C5 @ Edmonton)				
Average [(2)]	**63.04**	**21**	52.26	57.97
Average Differential WTI-Condensate (Premium)/Discount	**(0.17)**	**(51)**	(0.35)	(2.57)
Average Differential WCS-Condensate (Premium)/Discount	**(24.45)**	**64**	(14.93)	(14.83)
Mixed Sweet Blend ("MSW" @ Edmonton)				
Average [(3)]	**56.98**	**18**	48.37	54.26
End of Period	**60.63**	**21**	50.07	53.03
Average Refined Product Prices				
Chicago Regular Unleaded Gasoline ("RUL")	**73.08**	**16**	63.13	74.36
Chicago Ultra-low Sulphur Diesel ("ULSD")	**81.35**	**27**	63.86	80.58
Refining Margin: Average 3-2-1 Crack Spreads [(4)]				
Chicago	**12.96**	**12**	11.54	21.09
Average Natural Gas Prices				
AECO (C$/Mcf) [(5)]	**1.85**	**(37)**	2.94	1.96
NYMEX (US$/Mcf)	**3.00**	**(10)**	3.32	2.93
Basis Differential NYMEX-AECO (US$/Mcf)	**1.52**	**38**	1.10	1.40
Foreign Exchange Rate (US$ per C$1)				
Average	**0.791**	**5**	0.756	0.787

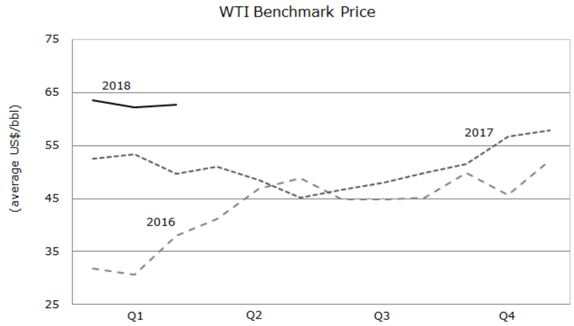
(1) These benchmark prices are not our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks tables in the Operating Results and Reportable Segments sections of this MD&A.
(2) The average Canadian dollar condensate benchmark price for the first quarter of 2018 was $79.70 per barrel (2017 – $69.13 per barrel).
(3) The average Canadian dollar MSW benchmark price for the first quarter of 2018 was $72.04 per barrel (2017 – $63.98 per barrel).
(4) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.
(5) Alberta Energy Company ("AECO") natural gas monthly index.

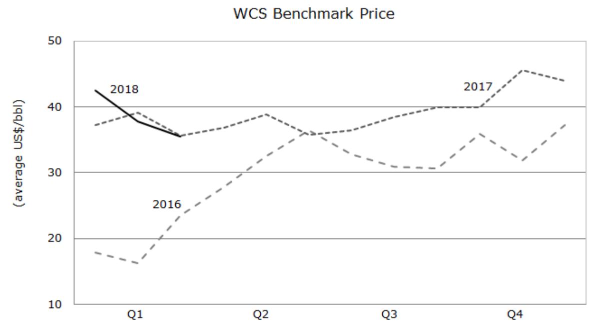
Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices improved in the first quarter of 2018 compared with the first three months of 2017. Compliance with the production cuts, as outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries ("OPEC") and Russia, led to widespread market expectations of an accelerated return to normal inventory levels despite the potential for additional U.S. supply from the Permian basin to offset reduced production.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In the first quarter of 2018, WTI benchmark prices weakened relative to Brent compared with 2017 as refineries in the U.S. midcontinent were unable to clear the crude oil inventory that accumulated subsequent to Hurricane Harvey and a series of planned turnarounds across the refining industry.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential widened significantly in the first three months of 2018 to levels not seen since the fourth quarter of 2013. WCS weakened relative to WTI due to increasing production in Alberta and limited pipeline capacity. Pipeline outages in the fourth quarter of 2017 forced additional volumes into storage and caused differentials to widen further. In addition, the oil and gas industry has been challenged in securing rail capacity to alleviate pipeline apportionment that has increased short-term pressure on differentials.





Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, diluent volumes as a percentage of total blended volumes, range from approximately 25 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 to transport the condensate to Edmonton.

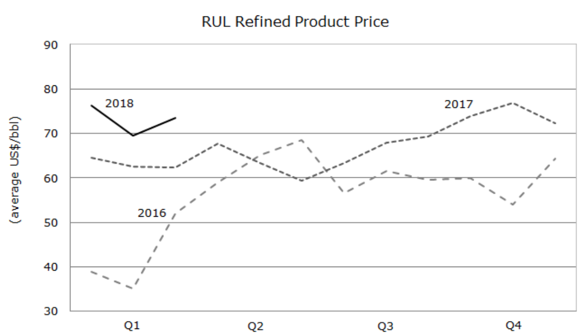
Average condensate prices were stronger relative to WTI in the first three months of 2018 compared with 2017 due to incremental demand for diluent as a result of increasing Alberta heavy oil production and minimal spare capacity on pipelines that increased the cost of transporting condensate to Edmonton.

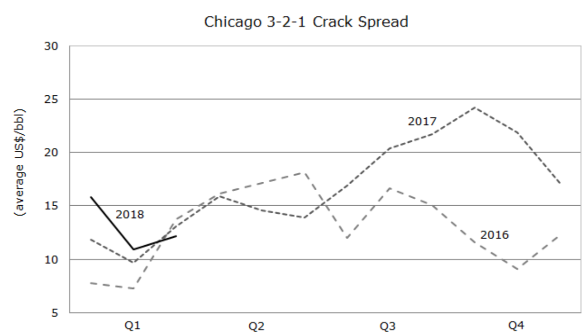
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price improved in the first quarter of 2018 compared with 2017, consistent with the general increase in average crude oil prices.

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 first quarter of 2018 primarily due to higher crude oil prices and wider Chicago 3-2-1 crack spreads. The widening of the Chicago 3-2-1 crack spreads was due to Hurricane Harvey and significant regional refinery maintenance, which caused a wider Brent-WTI differential. Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average AECO prices weakened compared with the first quarter of 2017 due to higher natural gas supply in Alberta, reduced export capabilities, and extensive pipeline and compressor station maintenance that decreased deliverability to storage facilities. Average NYMEX prices also decreased compared with the first quarter of 2017 as the market continues to expect higher supply.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGL's, natural gas and refined products are determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported results. Likewise, as the Canadian dollar weakens, there is a positive impact on our reported results. In addition to our revenues being denominated in U.S. dollars, 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 first quarter of 2018, the Canadian dollar relative to the U.S. dollar strengthened compared with the first three months of 2017, which had a negative impact of approximately $213 million on our revenues, excluding our Conventional segment. The Canadian dollar as at March 31, 2018 compared with December 31, 2017 was weaker relative to the U.S. dollar, resulting in $267 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The impact of the Acquisition, condensate prices rising, realized risk management losses and significantly wider light-heavy crude oil price differentials were the primary drivers of our financial results in the three months ended March 31, 2018. The following key performance measures are discussed in more detail within this MD&A.

	2018	2017				2016			
($ millions, except per share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenues	**4,610**	5,079	4,386	4,037	3,541	3,324	2,945	2,746	1,991
Operating Margin (1)									
From Continuing Operations	**157**	1,018	1,097	572	305	442	335	424	22
Total Operating Margin	**169**	1,088	1,214	731	450	595	487	541	144
Cash From Operating Activities									
From Continuing Operations	**(134)**	833	481	1,102	195	22	189	121	94
Total Cash From Operating Activities	**(123)**	900	592	1,239	328	164	310	205	182
Adjusted Funds Flow (2)									
From Continuing Operations	**(53)**	796	865	603	183	382	296	352	(65)
Total Adjusted Funds Flow	**(41)**	866	980	745	323	535	422	440	26
Operating Earnings (Loss) (2)									
From Continuing Operations	**(752)**	(533)	240	298	(39)	21	(40)	(3)	(269)
Per Share – Diluted ($)	**(0.61)**	(0.43)	0.20	0.27	(0.05)	0.03	(0.05)	-	(0.32)
Total Operating Earnings (Loss)	**(743)**	(514)	327	352	(39)	321	(236)	(39)	(423)
Per Share – Diluted ($)	**(0.60)**	(0.42)	0.27	0.32	(0.05)	0.39	(0.28)	(0.05)	(0.51)
Net Earnings (Loss)									
From Continuing Operations	**(914)**	(776)	275	2,558	211	(209)	(55)	(231)	36
Per Share – Diluted ($)	**(0.74)**	(0.63)	0.22	2.30	0.25	(0.25)	(0.07)	(0.28)	0.04
Total Net Earnings (Loss)	**(654)**	620	(82)	2,617	211	91	(251)	(267)	(118)
Per Share – Diluted ($)	**(0.53)**	0.50	(0.07)	2.35	0.25	0.11	(0.30)	(0.32)	(0.14)
Capital Investment (3)									
From Continuing Operations	**522**	557	396	277	225	202	167	202	284
Total Capital Investment	**524**	583	438	327	313	259	208	236	323
Dividends									
Cash Dividends	**60**	61	62	61	41	42	41	42	41
Per Share ($)	**0.05**	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05

(1) Additional subtotal found in Notes 1 and 8 of the interim Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets and assets held for sale.

Revenues

($ millions)	
Revenues for the Three Months Ended March 31, 2017	**3,541**
Increase (Decrease) due to:	
Oil Sands	**1,313**
Deep Basin	**224**
Refining and Marketing	**(372)**
Corporate and Eliminations	**(96)**
Revenues for the Three Months Ended March 31, 2018	**4,610**

Upstream revenues from continuing operations increased significantly in the first quarter of 2018 compared with 2017. The rise was primarily related to incremental sales volumes as a result of the Acquisition, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar, lower average realized pricing consistent with the materially wider discount in heavy crude oil pricing, and higher royalties.

Refining and Marketing revenues decreased 14 percent compared with the first quarter of 2017. Refining revenues increased primarily due to higher refined product pricing, consistent with the rise in average Chicago refined product benchmark prices, partially offset by lower crude utilization associated with the major planned turnarounds in 2018. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group decreased significantly in the first quarter of 2018 compared with 2017 due to a decline in crude oil and natural gas volumes sold, as well as lower natural gas prices, partially offset by higher crude oil prices.

Corporate and Eliminations revenues relate to sales of natural gas or crude oil and operating revenue between segments and are recorded at transfer prices based on current market prices.

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

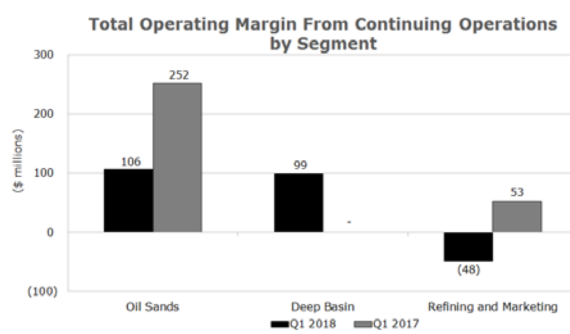
Operating Margin

Operating Margin is an additional subtotal found in Notes 1 and 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.

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Revenues	**4,804**	3,639
(Add) Deduct:		
Purchased Product	**1,957**	2,330
Transportation and Blending	**1,517**	566
Operating Expenses	**705**	359
Realized (Gain) Loss on Risk Management Activities	**468**	79
Operating Margin From Continuing Operations	**157**	305
Conventional (Discontinued Operations)	**12**	145
Total Operating Margin	**169**	450

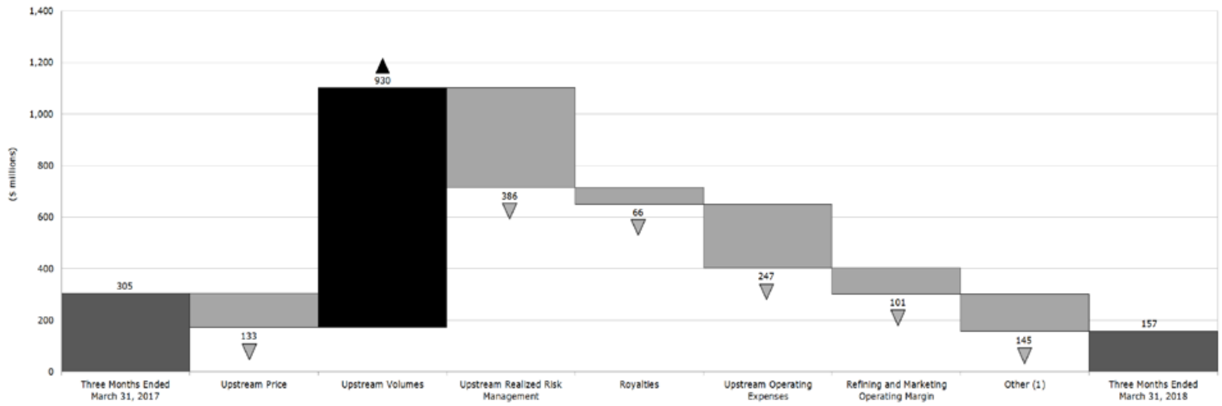
Operating Margin from continuing operations decreased in the first three months of 2018 compared with 2017 primarily due to:

- A rise in transportation and blending expenses primarily due to higher condensate prices along with an increase in condensate volumes required for blending our increased oil sands production;
- Realized risk management losses of $468 million, compared with losses of $79 million in 2017;
- An increase in upstream operating expenses primarily due to the Acquisition;
- Lower Operating Margin from Refining and Marketing due to higher operating costs and a decline in crude utilization rates; and
- Materially wider light-heavy crude oil differentials.



These decreases in Operating Margin from continuing operations were partially offset by increased sales volumes as a result of the Acquisition.

Operating Margin From Continuing Operations 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 from continuing operations can be found in the Reportable Segments section of this MD&A.

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of current assets and current liabilities, excluding cash and cash equivalents, risk management, the contingent payment, assets held for sale and liabilities related to assets held for sale. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

Total Cash From Operating Activities and Adjusted Funds Flow

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Cash From Operating Activities [1]	**(123)**	328
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(18)**	(31)
Net Change in Non-Cash Working Capital	**(64)**	36
Adjusted Funds Flow [1]	**(41)**	323

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

Cash From Operating Activities and Adjusted Funds Flow decreased compared with the first quarter of 2017 due to lower Operating Margin, as discussed above, and an increase in general and administrative costs primarily due to a non-cash expense of $59 million incurred in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and $43 million related to severance costs in the quarter.

The change in non-cash working capital in the first quarter of 2018 was primarily due to a decrease in accounts payable and income tax payable, partially offset by a decrease in accounts receivable. For the three months ended March 31, 2017, the change in non-cash working capital was primarily due to a decline in accounts receivable, partially offset by a decrease in accounts payable.

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.

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Earnings (Loss) From Continuing Operations, Before Income Tax	**(1,072)**	260
Add (Deduct):		
Unrealized Risk Management (Gain) Loss [1]	**(139)**	(279)
Non-Operating Unrealized Foreign Exchange (Gain) Loss [2]	**264**	(56)
(Gain) Loss on Divestiture of Assets	**-**	1
Other	**(1)**	-
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**(948)**	(74)
Income Tax Expense (Recovery)	**(196)**	(35)
Operating Earnings (Loss) From Continuing Operations	**(752)**	(39)
Operating Earnings (Loss) From Discontinued Operations	**9**	-
Total Operating Earnings (Loss)	**(743)**	(39)

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

Operating Earnings from continuing operations decreased in the first quarter of 2018 compared with 2017 primarily due to lower cash from operating activities and Adjusted Funds Flow, as discussed above, an increase in DD&A which included an impairment of $100 million, a re-measurement loss of $117 million on the contingent payment, a non-cash expense of $59 million incurred in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and unrealized foreign exchange losses on operating items compared with gains in 2017.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss) From Continuing Operations, for the Three Months Ended March 31, 2017	**211**
Increase (Decrease) due to:	
Operating Margin From Continuing Operations	**(148)**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**(140)**
Unrealized Foreign Exchange Gain (Loss)	**(354)**
Re-measurement of Contingent Payment	**(117)**
Gain (Loss) on Divestiture of Assets	**1**
Expenses [1]	**(179)**
DD&A	**(393)**
Exploration Expense	**(2)**
Income Tax Recovery (Expense)	**207**
Net Earnings (Loss) From Continuing Operations, for the Three Months Ended March 31, 2018	**(914)**

(1) Includes Corporate and Eliminations 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.

In the first quarter of 2018, we incurred a net loss from continuing operations due to:

- Lower Operating Earnings, as discussed above;
- Non-operating unrealized foreign exchange losses of $264 million compared with gains of $56 million in 2017; and
- Unrealized risk management gains of $139 million compared with gains of $279 million in 2017.

Net Earnings from discontinued operations for the three months ended March 31, 2018 was $260 million (2017 – $nil), including a before-tax gain of $348 million on the divestiture of the Suffield asset.

Net Capital Investment

($ millions)	Three Months Ended March 31, 2018	2017
Oil Sands	**318**	172
Deep Basin	**145**	-
Refining and Marketing	**53**	46
Corporate and Eliminations	**6**	7
Capital Investment - Continuing Operations	**522**	225
Conventional (Discontinued Operations)	**2**	88
Total Capital Investment	**524**	313
Acquisitions	**5**	-
Divestitures	**(453)**	-
Net Capital Investment [1]	**76**	313

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

Capital investment in continuing operations in the first quarter of 2018 increased $297 million compared with the first quarter of 2017, reflecting our increased ownership in FCCL and the new asset base in the Deep Basin as a result of the Acquisition. Oil Sands capital investment focused on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells; and the Christina Lake phase G expansion. Capital investment in the Deep Basin focused on all three operating areas and included the drilling of 14 horizontal production wells targeting liquids rich natural gas, as well as capital invested in facilities and infrastructure to support production growth.

Refining and Marketing capital investment increased $7 million in the first quarter of 2018 due to increased capital maintenance and reliability work compared with the same period in 2017.

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

Capital Investment Decisions

We continue to focus on deleveraging our balance sheet. To achieve this, we are currently marketing for sale certain non-core Deep Basin Assets and are continuing to look for opportunities to further streamline our portfolio. In addition to our commitment to continue reducing our debt, we are actively identifying further cost reduction opportunities.

Once our balance sheet leverage is more in line with our target debt metric, our disciplined approach to capital allocation includes prioritizing our uses of cash in the following manner:

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

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics, which position us to be financially resilient in times of lower cash flows. In addition, we continue to evaluate other corporate and financial opportunities, including generating cash from our existing portfolio. Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	Three Months Ended March 31, 2018	2017
Adjusted Funds Flow [1]	**(41)**	323
Total Capital Investment [1]	**524**	313
Free Funds Flow [1] [2]	**(565)**	10
Cash Dividends	**60**	41
	(625)	(31)

(1) Includes our Conventional segment, which has been classified as a discontinued operation.
(2) Free Funds Flow is a non-GAAP measure defined as Adjusted Funds Flow less capital investment.

We expect our capital investment and cash dividends for 2018 to be funded from our internally generated cash flows and our cash balance on hand.

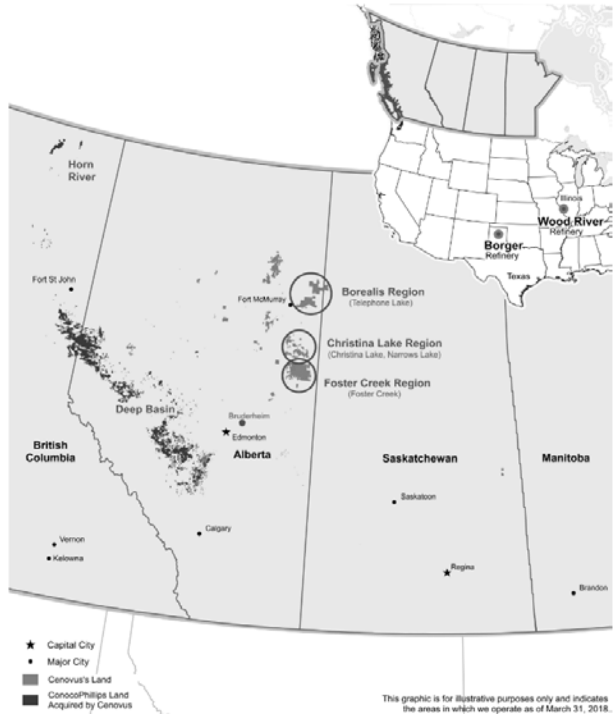
REPORTABLE SEGMENTS

Our reportable segments are as follows:

Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. 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. These assets were acquired on May 17, 2017.

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 include adjustments for internal usage of natural gas production between segments, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

In the second quarter of 2017, Cenovus announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. The associated assets and liabilities were reclassified as held for sale and the results of operations reported as a discontinued operation. As at January 5, 2018, all of the Conventional segment assets were sold. Refer to the Discontinued Operations section of this MD&A for more information.

Revenues by Reportable Segment

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Oil Sands	**2,348**	1,035
Deep Basin	**224**	-
Refining and Marketing	**2,232**	2,604
Corporate and Eliminations	**(194)**	(98)
	4,610	3,541

OIL SANDS

In northeastern Alberta, we own 100 percent of the Foster Creek, Christina Lake and Narrows Lake oil sands projects following the completion of the Acquisition. In addition, we have several emerging projects in the early stages of development. The Oil Sands segment 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 for the first quarter of 2018 compared with 2017 include:

- Temporarily reducing production levels in February and March in response to market access constraints and discounted heavy crude oil pricing;
- Crude oil netbacks, excluding realized risk management activities, of $17.10 per barrel, a 21 percent decrease compared with the first quarter of 2017 primarily due to the materially wider WCS-Condensate price differential impacting our average realized sales price; and
- Operating Margin of $106 million, a decrease of $146 million due primarily to increased transportation and blending costs and realized risk management losses of $454 million.

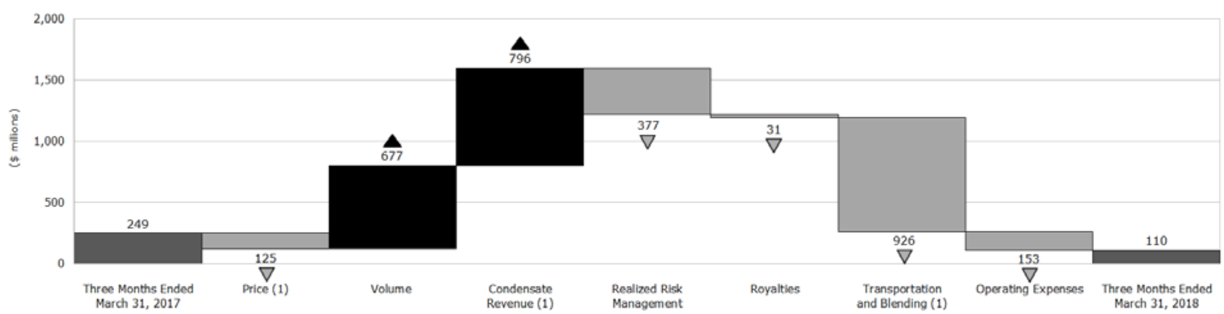
Oil Sands – Crude Oil

Financial Results

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Gross Sales	**2,403**	1,055
Less: Royalties	**58**	27
Revenues	**2,345**	1,028
Expenses		
Transportation and Blending	**1,492**	566
Operating	**289**	136
(Gain) Loss on Risk Management	**454**	77
Operating Margin	**110**	249
Capital Investment	**317**	169
Operating Margin Net of Related Capital Investment	**(207)**	80

Capital investment in excess of Operating Margin from Oil Sands was funded through cash on our balance sheet.

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 first quarter of 2018, our average crude oil sales price decreased to $34.27 per barrel (2017 – $38.08 per barrel). The decrease in our crude oil price resulted from the widening of the WCS-Condensate and the WCS-Christina Dilbit Blend ("CDB") differentials and the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential widened to a discount of US$2.68 per barrel (2017 – discount of US$1.79 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 crude oil 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 March 31,		
(barrels per day)	**2018**	**Percent Change**	2017
Foster Creek	**157,390**	**95**	80,866
Christina Lake	**202,276**	**101**	100,635
	359,666	**98**	181,501

In the first quarter of 2018, production increased primarily due to the Acquisition. Production was also impacted by our decision to temporarily reduce volumes produced in response to takeaway capacity constraints and wider light-heavy crude oil price differentials. We have significant capacity to store barrels not yet produced within our oil sands reservoirs, allowing flexibility to produce and sell those barrels at a later date when pipeline capacity improves and crude oil differentials narrow.

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 a wider WCS-Condensate differential in the first quarter of 2018, the proportion of the cost of condensate recovered decreased. The total amount of condensate used increased as a result of higher production volumes.

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.

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 March 31,	
(percent)	**2018**	2017
Foster Creek	**10.4**	8.5
Christina Lake	**2.3**	2.7

Royalties increased $31 million in the first quarter of 2018 compared with 2017. Royalties at both Foster Creek and Christina Lake increased primarily due to increased sales volumes and a higher WTI benchmark price (which determines the royalty rate), partially offset by lower crude oil sales prices.

Expenses

Transportation and Blending

In the first quarter of 2018, transportation and blending costs increased $926 million compared to the first quarter of 2017. Blending costs increased due to a rise in condensate volumes required for our increased production and higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price, 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 incremental sales volumes as a result of the Acquisition.

Per-unit Transportation Expenses

At Foster Creek and Christina Lake, per-barrel transportation costs increased as a result of higher transportation and storage costs, as well as costs associated with transporting additional volumes in the quarter.

Operating

Primary drivers of our operating expenses in the first quarter of 2018 were workforce costs, fuel, chemical costs, repairs and maintenance and workovers. While per-barrel operating costs decreased two percent, total operating expenses increased $153 million primarily due to the Acquisition, higher chemical costs, and additional repairs and maintenance.

Per-unit Operating Expenses

	Three Months Ended March 31,		
($/bbl)	**2018**	**Percent Change**	2017
Foster Creek			
Fuel	**2.77**	**(5)**	2.93
Non-fuel	**7.74**	**10**	7.06
Total	**10.51**	**5**	9.99
Christina Lake			
Fuel	**2.35**	**(9)**	2.57
Non-fuel	**5.03**	**(9)**	5.51
Total	**7.38**	**(9)**	8.08
Total	**8.78**	**(2)**	8.97

At Foster Creek, per-barrel fuel costs decreased due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses increased in the first quarter of 2018 primarily due to a true-up of the emissions charges under the Specified Gas Emitters Regulation ("SGER") being recognized in the first quarter of 2017, higher chemical costs and increased repairs and maintenance, partially offset by higher sales volumes.

At Christina Lake, fuel costs declined on a per-barrel basis due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses decreased primarily due to higher sales volumes and a true-up of the emissions charges under the SGER being recognized in the first quarter of 2017. These decreases were partially offset by increased chemical costs associated with the phase F expansion, as well as higher repairs and maintenance activities.

Netbacks [1]

	Foster Creek		Christina Lake	
	Three Months Ended March 31,			
($/bbl)	**2018**	2017	**2018**	2017
Sales Price	**39.29**	40.62	**30.20**	35.86
Royalties	**3.17**	2.83	**0.59**	0.86
Transportation and Blending	**8.93**	7.72	**4.78**	4.13
Operating Expenses	**10.51**	9.99	**7.38**	8.08
Netback Excluding Realized Risk Management	**16.68**	20.08	**17.45**	22.79
Realized Risk Management Gain (Loss)	**(13.53)**	(5.73)	**(13.99)**	(4.52)
Netback Including Realized Risk Management	**3.15**	14.35	**3.46**	18.27

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

Risk Management

Risk management activities in the first quarter of 2018 resulted in realized losses of $454 million (2017 – realized losses of $77 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 in the first quarter of 2018, net of internal usage, was 4 MMcf per day (2017 – 15 MMcf per day).

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2018	2017
Foster Creek	**139**	70
Christina Lake	**164**	63
	303	133
Narrows Lake	**4**	5
Other [1]	**11**	34
Capital Investment [2]	**318**	172

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

Capital investment in the first quarter of 2018 increased by $146 million from 2017, reflecting our 100 percent ownership of FCCL as of May 17, 2017. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells.

In the first quarter of 2018, Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells and the phase G expansion. Capital investment in the first quarter of 2017 focused on sustaining capital related to existing production and stratigraphic test wells.

Capital investment at Narrows Lake in the first quarter of 2018 primarily related to equipment and site preservation.

Drilling Activity

	Gross Stratigraphic Test Wells		Gross Production Wells [1]	
Three Months Ended March 31,	**2018**	2017	**2018**	2017
Foster Creek	**43**	92	**8**	-
Christina Lake	**63**	98	**14**	-
	106	190	**22**	-
Narrows Lake	**-**	2	**-**	-
Other	**2**	14	**-**	-
	108	206	**22**	-

(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

Foster Creek is currently producing from phases A through G. Capital investment for 2018 is forecast to be between $500 million and $550 million. We plan to continue focusing on sustaining capital related to existing production.

Christina Lake is producing from phases A through F. Capital investment for 2018 is forecast to be between $500 million and $550 million, focused on sustaining capital and construction of the phase G expansion. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, is progressing well and remains on track. Phase G is expected to start producing in the second half of 2019.

Capital investment at Narrows Lake in 2018 is forecast to be between $5 million and $10 million and will focus primarily on equipment and site preservation related to the suspension of construction at Narrows Lake.

In 2018, our Technology and other capital, forecast to be between $35 million and $45 million, relates to technology development initiatives and annual environmental and regulatory commitments.

Our 2018 Oil Sands total capital investment is forecast to be between $1,040 million and $1,155 million. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves.

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

($ millions, unless otherwise indicated)	As at December 31, 2017
Upstream Property, Plant and Equipment	26,341
Estimated Future Development Capital	30,195
Total Estimated Upstream Cost Base	56,536
Total Proved Reserves (MMBOE)	5,232
Implied Depletion Rate ($/BOE)	10.81

While this illustrates the calculation of the implied depletion rate, our depletion rates resulted in a total average rate ranging between $8.75 to $11.30 per BOE. Amounts related to assets under construction and assets held for sale, 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, 2017 Consolidated Financial Statements.

Future development costs declined due to an increase in well pair lengths at Christina Lake, resulting in a reduction in the number of pads and well pairs required, as well as 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 the future development costs at Foster Creek as a result of a development area expansion.

In the first quarter of 2018, Oil Sands DD&A increased $192 million primarily due to higher sales volumes as a result of the Acquisition. The average DD&A rate in the first quarter of 2018 was approximately $10.65 per barrel, consistent with the first quarter of 2017 (2017 – $10.70 per barrel).

There was $2 million of exploration expense recorded in the first quarter of 2018 (2017 – $ nil).

DEEP BASIN

Our Deep Basin Assets include liquids rich natural gas, condensate and other NGLs, as well as light and medium oil located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities. The Deep Basin Assets provide short-cycle development opportunities with high-return potential that complement our long-term oil sands development. In addition, a portion of the natural gas produced is used as fuel in our oil sands operations and provides an economic hedge for the natural gas required as a fuel source at the Refineries.

Significant developments in our Deep Basin segment in the first quarter of 2018 include:

- Total production of 127,056 BOE per day;
- Total capital investment of $145 million related to the drilling of 14 horizontal production wells targeting liquids rich natural gas, and included capital investment in facilities and infrastructure to support production growth;
- Netback of $8.99 per BOE, before realized hedging; and
- Generating Operating Margin of $99 million.

Financial Results

($ millions)	Three Months Ended March 31, 2018
Gross Sales	259
Less: Royalties	35
Revenues	224
Expenses	
Transportation and Blending	25
Operating	91
(Gain) Loss on Risk Management	9
Operating Margin	99
Capital Investment	145
Operating Margin Net of Related Capital Investment	(46)

Revenues

Price

	Three Months Ended March 31, 2018
Light and Medium Oil ($/bbl)	67.30
NGLs ($/bbl)	37.73
Natural Gas ($/mcf)	2.23
Total Oil Equivalent ($/BOE)	21.68

In the first quarter of 2018, revenues included $12 million of processing fee revenue related to our interests in natural gas processing facilities. We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	Three Months Ended March 31, 2018
Liquids	
Crude Oil (barrels per day)	**6,517**
NGLs (barrels per day)	**28,962**
	35,479
Natural Gas (MMcf per day)	**549**
Total Production (BOE/d)	**127,056**
Natural Gas Production (percentage of total)	**72**
Liquids Production (percentage of total)	**28**

Royalties

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

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

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

In the first quarter of 2018, our effective royalty rate was 23.1 percent for liquids and 6.0 percent for natural gas.

Expenses

Transportation

Transportation costs averaged $2.21 per BOE in the first quarter of 2018 and reflects charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. The majority of Deep Basin production is sold into the Alberta market.

Operating

Primary drivers of our operating expenses were related to workforce, repairs and maintenance, processing fee expenses, and property tax and lease costs. We continued to focus on optimization of maintenance processes in the first quarter of 2018, resulting in increased runtimes and lower repairs and maintenance costs, as well as a reduction in workforce costs and higher production levels. Operating costs averaged $7.36 per BOE in the first three months of 2018.

Netbacks

($/BOE)	Three Months Ended March 31, 2018
Sales Price	**21.68**
Royalties	**3.09**
Transportation and Blending	**2.21**
Operating Expenses	**7.36**
Production and Mineral Taxes	**0.03**
Netback Excluding Realized Risk Management	**8.99**
Realized Risk Management Gain (Loss)	**(0.80)**
Netback Including Realized Risk Management	**8.19**

Deep Basin – Capital Investment

In the first three months of 2018, capital investment was focused on developing all three operating areas. We drilled 12 operated net horizontal wells in addition to participating in the drilling of two non-operated net horizontal wells targeting liquids rich natural gas, completed 16 wells, and brought 17 wells on production. In the first quarter of 2018, Cenovus invested $35 million on facilities and infrastructure to support production growth in our core development areas.

($ millions)	Three Months Ended March 31, 2018
Drilling and Completions	**94**
Facilities	**35**
Other	**16**
Capital Investment (1)	**145**

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

Drilling Activity

The following table summarizes Cenovus's well activity:

	Three Months Ended March 31, 2018			
(net wells, unless otherwise stated)	**Elmworth-Wapiti**	**Kaybob-Edson**	**Clearwater**	**Total Deep Basin**
Drilled (1)	**4**	**7**	**3**	**14**
Completed	**6**	**8**	**2**	**16**
Tied-in	**9**	**4**	**4**	**17**

(1) Includes 12 operated net horizontal wells and two non-operated net horizontal wells.

Future Capital Investment

Our 2018 Deep Basin capital investment is forecast to be between $175 million and $195 million.

We continue to take a disciplined approach to the development of our Deep Basin assets. We plan to focus capital investment on drilling, completion and tie-in opportunities that have the potential to generate strong returns and increase throughput at underutilized facilities and evaluating portfolio opportunities. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

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. The average depletion rate was approximately $10.40 per BOE in the first quarter of 2018.

As at March 31, 2018, it was determined that the carrying amount of the Clearwater cash-generating unit ("CGU") exceeded its recoverable amount, resulting in an impairment loss of $100 million. The impairment was recorded as additional DD&A. Future cash flows for the CGU declined due to forward natural gas prices. Total Deep Basin DD&A was $204 million in the three months ended March 31, 2018.

Assets and Liabilities Held for Sale

In the fourth quarter of 2017, we commenced marketing for sale certain non-core assets located primarily in the East Clearwater area. The properties currently produce approximately 15,000 BOE per day of natural gas and NGLs. These assets were reclassified as assets held for sale and recorded at the lesser of their carrying amount and fair value less costs to sell.

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.

Significant developments that impacted our Refining and Marketing segment in the first quarter of 2018 compared with 2017 include:

- Substantially completing major planned turnaround activity at the Wood River refinery, representing the largest scale turnaround to date; and
- Completing the majority of planned turnaround activity at the Borger refinery.

Refinery Operations [(1)]

	Three Months Ended March 31,	
	2018	2017
Crude Oil Capacity (Mbbls/d)	**460**	460
Crude Oil Runs (Mbbls/d)	**349**	406
Heavy Crude Oil	**162**	200
Light/Medium	**187**	206
Refined Products (Mbbls/d)	**369**	433
Gasoline	**189**	227
Distillate	**120**	131
Other	**60**	75
Crude Utilization (percent)	**76**	88

(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.

Crude oil runs and refined product output in the first three months of 2018 decreased relative to the first quarter of 2017 due to the major planned turnarounds and maintenance at both refineries. In addition, lower heavy crude oil volumes were processed due to optimization of the total crude input slate.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Revenues	**2,232**	2,604
Purchased Product	**1,957**	2,330
Gross Margin	**275**	274
Expenses		
Operating	**318**	219
(Gain) Loss on Risk Management	**5**	2
Operating Margin	**(48)**	53
Capital Investment	**53**	46
Operating Margin Net of Related Capital Investment	**(101)**	7

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 first quarter of 2018, Refining and Marketing gross margin increased primarily due to:

- Wider heavy crude oil differentials, decreasing feedstock costs; and
- Higher average market crack spreads.

These increases in gross margin were partially offset by:

- Reduced crude utilization as a result of greater planned maintenance and turnarounds during the quarter; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately $12 million on our gross margin.

In the first quarter of 2018, the cost of Renewable Identification Numbers ("RINs") was $47 million (2017 – $61 million). The cost of RINs declined due to the decrease in RINs benchmark prices and lower volume obligations due to the turnarounds.

Operating Expense

Primary drivers of operating expenses were maintenance, labour, and utilities. In the first quarter of 2018, operating expenses increased primarily due to an increase in maintenance costs associated with the planned maintenance and turnarounds, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar.

Refining and Marketing – Capital Investment

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Wood River Refinery	**35**	34
Borger Refinery	**17**	12
Marketing	**1**	-
	53	46

Capital expenditures increased $7 million relative to the first quarter of 2017 and focused primarily on capital maintenance and reliability work.

In 2018, we expect to invest between $180 million and $210 million mainly related to capital maintenance and reliability work. For more information, we direct our readers to review the news release for our 2018 guidance dated December 13, 2017. The news release is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com.

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 was $54 million in the first quarter of 2018, consistent with the same period of 2017.

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 including natural gas and crude oil sales and purchases. 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 and losses, if any, on interest rate swaps and foreign exchange contracts. In the first three months of 2018, our risk management activities resulted in $139 million of unrealized gains (2017 – $279 million). As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates.

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

	Three Months Ended March 31,	
($ millions)	**2018**	2017
General and Administrative	**179**	43
Finance Costs	**150**	99
Interest Income	**(3)**	(17)
Foreign Exchange (Gain) Loss, Net	**277**	(76)
Transaction Costs	**-**	29
Re-measurement of Contingent Payment	**117**	-
Research Costs	**12**	4
(Gain) Loss on Divestiture of Assets	**-**	1
Other (Income) Loss, Net	**(2)**	-
	730	83

Expenses

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs and office rent. General and administrative expenses increased by $136 million in the first three months of 2018 compared with 2017 due to a non-cash expense of $59 million recorded in connection with certain Calgary office space in excess of Cenovus's current and near-term requirements, and $43 million related to severance costs in the quarter.

Non-rent G&A was $0.92 per BOE, excluding severance charges incurred in the quarter.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. Finance costs increased by $51 million in the first quarter of 2018 compared to 2017 primarily due to costs associated with the US$2.9 billion of senior unsecured notes issued to finance the Acquisition in 2017.

The weighted average interest rate on outstanding debt for the first quarter of 2018 was 5.1 percent (2017 – 5.3 percent).

Foreign Exchange

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Unrealized Foreign Exchange (Gain) Loss	**282**	(72)
Realized Foreign Exchange (Gain) Loss	**(5)**	(4)
	277	(76)

In the first quarter of 2018, unrealized foreign exchange losses of $267 million resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at March 31, 2018 weakened by three percent in comparison to December 31, 2017, resulting in unrealized losses.

Transaction Costs

In the first quarter of 2017, we expensed $29 million of transaction costs related to the Acquisition.

Re-measurement of Contingent Payment

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

The contingent payment is accounted for as a financial option. The fair value of $323 million as at March 31, 2018 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the three months ended March 31, 2018 a non-cash re-measurement loss of $117 million was recorded. As at March 31, 2018, no amount is payable under this agreement.

Average WCS forward pricing for the remaining term of the contingent payment is US$36.14 or C$46.60 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$39.30 per barrel and C$57.50 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 for the three months ended March 31, 2018 was $15 million (2017 – $18 million).

Income Tax

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Current Tax		
Canada	**(58)**	(26)
United States	**4**	(1)
Current Tax Expense (Recovery)	**(54)**	(27)
Deferred Tax Expense (Recovery)	**(104)**	76
Total Tax Expense (Recovery) From Continuing Operations	**(158)**	49

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.

A current tax recovery from continuing operations was recorded in the first quarter of 2018 and 2017 due to the carryback of current and prior year losses.

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

DISCONTINUED OPERATIONS

In 2017, Cenovus divested the majority of its Conventional segment which included its heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. The associated assets and liabilities were reclassified as held for sale and the results of operations reported as a discontinued operation.

The sale of Suffield, the only remaining legacy Conventional asset as at December 31, 2017, closed on January 5, 2018 for gross proceeds of $512 million, before closing adjustments, and a $348 million before-tax gain on discontinuance.

Financial Results

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Gross Sales	**16**	374
Less: Royalties	**(1)**	50
Revenues	**17**	324
Expenses		
Transportation and Blending	**1**	51
Operating	**5**	110
Production and Mineral Taxes	**(1)**	5
(Gain) Loss on Risk Management	**-**	13
Operating Margin	**12**	145
Depreciation, Depletion and Amortization	**-**	121
Exploration Expense	**-**	3
Finance Costs	**-**	21
Earnings (Loss) From Discontinued Operations Before Income Tax	**12**	-
Current Tax Expense (Recovery)	**-**	5
Deferred Tax Expense (Recovery)	**3**	(5)
After-tax Earnings (Loss) From Discontinued Operations	**9**	-
After-tax Gain (Loss) on Discontinuance (1)	**251**	-
Net Earnings (Loss) From Discontinued Operations	**260**	-

(1) *Net of deferred tax expense of $93 million in the three months ended March 31, 2018.*

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended March 31,	
($ millions)	**2018**	2017
Cash From (Used In)		
Operating Activities – Continuing Operations	**(134)**	195
Operating Activities – Discontinued Operations	**11**	133
Total Operating Activities	**(123)**	328
Investing Activities – Continuing Operations	**(490)**	(371)
Investing Activities – Discontinued Operations	**451**	(88)
Total Investing Activities	**(39)**	(459)
Net Cash Provided (Used) Before Financing Activities	**(162)**	(131)
Financing Activities	**(59)**	(52)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**16**	11
Increase (Decrease) in Cash and Cash Equivalents	**(205)**	(172)

	March 31, 2018	December 31, 2017
Cash and Cash Equivalents	**405**	610
Committed and Undrawn Credit Facility	**4,500**	4,500

Cash From (Used In) Operating Activities

In the first three months of 2018, cash was used in operating activities in comparison with cash generated by operating activities in the first quarter of 2017. This occurred as a result of lower Operating Margin, as discussed in the Financial Results section of this MD&A, higher general and administrative expenses and an increase in finance costs, as discussed in the Corporate and Eliminations section of this MD&A. Excluding risk management assets and liabilities, assets and liabilities held for sale, and the current portion of the contingent payment, our working capital was $1,052 million at March 31, 2018 compared with $1,133 million at December 31, 2017.

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

Cash From (Used In) Investing Activities

In the first quarter of 2018, the increase in cash used in investing activities from continuing operations was primarily due to an increase in capital investment reflecting our increased ownership in FCCL and the new asset base in the Deep Basin, partially offset by $456 million in net proceeds from the divestiture of our Suffield asset. In 2017, capital investment was limited due to spending reductions in response to the low commodity price environment.

Cash From (Used In) Financing Activities

Cash used in financing activities increased in 2018 primarily due to a higher dividend payment driven by an increased number of shares outstanding. In 2017 we incurred higher financing costs related to the issuance of debt and common shares.

Total debt as at March 31, 2018 was $9,781 million (December 31, 2017 – $9,513 million), with no principal payments due until October 15, 2019 (US$1.3 billion). The principal amount of long-term debt outstanding in U.S. dollars remained unchanged since December 31, 2017, with the increase in total debt due to the weakening of the Canadian dollar relative to the U.S. dollar.

As at March 31, 2018, we were in compliance with all of the terms of our debt agreements.

Dividends

In the first quarter of 2018, we paid dividends of $0.05 per share or $60 million (2017 – $0.05 per share or $41 million). 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 upstream and refining operations to fund all of our cash requirements in 2018. Any potential shortfalls may be funded through prudent use of our balance sheet capacity including draws on our credit facility, 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 March 31, 2018:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**405**
Committed Credit Facility – Tranche A	**November 2021**	**3,300**
Committed Credit Facility – Tranche B	**November 2020**	**1,200**

Committed Credit Facility

We have a committed credit facility in place that consists of a $1.2 billion tranche maturing on November 30, 2020 and $3.3 billion tranche maturing on November 30, 2021. As of March 31, 2018, no amounts were drawn on 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.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in November 2019. As at March 31, 2018, US$4.6 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

Financial Metrics

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

As at	**March 31, 2018**	December 31, 2017
Net Debt to Capitalization (percent)	**33**	31
Net Debt to Adjusted EBITDA	**3.3x**	2.8x

Over the long term, Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on our credit facility or repay existing debt, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new debt, or issue new shares.

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

Share Capital and Stock-Based Compensation Plans

As at March 31, 2018, there were approximately 1,229 million common shares outstanding (December 31, 2017 – 1,229 million common shares). In the second quarter of 2017, Cenovus closed a bought-deal common share financing 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, Cenovus 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, restricted ConocoPhillips from selling or hedging its Cenovus common shares until after November 17, 2017. ConocoPhillips is also restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the then outstanding common shares of Cenovus. As at March 31, 2018, ConocoPhillips continued to hold these common shares.

Refer to Note 20 of the interim Consolidated Financial Statements for more details on our Stock Option Plan and our Performance Share Unit, Restricted Share Unit and Deferred Share Unit Plans.

As at March 31, 2018	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**40,385**	**31,631**
Other Stock-Based Compensation Plans	**15,251**	**1,613**

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 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, 2017 Consolidated Financial Statements.

As at March 31, 2018, total commitments were $21.5 billion, of which $18.2 billion were for various transportation commitments. Transportation commitments include $9 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2017 – $9 billion). These agreements are for terms up to 20 years subsequent to the date of commencement.

We continue to focus on near and mid-term strategies to broaden market access for our crude oil production. We continue to support proposed new pipeline projects that would connect us to new markets in the U.S. and globally, moving our crude oil production to market by rail, and assessing options to maximize the value of our crude oil.

As at March 31, 2018, there were outstanding letters of credit aggregating $432 million issued as security for performance under certain contracts (December 31, 2017 – $376 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 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 March 31, 2018, the estimated fair value of the contingent payment was $323 million. See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

For a full understanding of the risks that impact Cenovus, the following discussion should be read in conjunction with the Risk Management and Risk Factors section of our 2017 annual MD&A.

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. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pay a dividend to our shareholders and may materially affect the market price of our securities.

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

Commodity Prices

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 22 and 23 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 managed 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 March 31,					
	2018			2017		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [1]	**463**	**(111)**	**352**	77	(251)	(174)
Refining	**5**	**(3)**	**2**	2	-	2
Interest Rate	**-**	**(25)**	**(25)**	-	(4)	(4)
Foreign Exchange	**1**	**-**	**1**	-	(24)	(24)
(Gain) Loss on Risk Management	**469**	**(139)**	**330**	79	(279)	(200)
Income Tax Expense (Recovery)	**(126)**	**37**	**(89)**	(21)	75	54
(Gain) Loss on Risk Management, After Tax	**343**	**(102)**	**241**	58	(204)	(146)

(1) *2017 excludes $13 million of realized risk management losses on crude oil contracts from our Conventional segment, which have been classified as a discontinued operation.*

In the first quarter of 2018, we incurred realized losses on crude oil risk management activities as the settlement price, consistent with the average benchmark prices, exceeded our contract prices. Unrealized gains were recorded on our crude oil financial instruments in the first quarter of 2018 primarily due to the realization of settled positions.

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 Consolidated Financial Statements.

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 three months ended March 31, 2018. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2017.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. There have been no changes to our key sources of estimation uncertainty during the three months ended March 31, 2018. Further information can be found in the notes to the Consolidated Financial Statements and annual MD&A for the year ended December 31, 2017.

Changes in Accounting Policies

Effective January 1, 2018, Cenovus adopted IFRS 9, "*Financial Instruments*" ("IFRS 9") replacing IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39"). The adoption of IFRS 9 did not have a material impact on our Consolidated Financial Statements.

Effective January 1, 2018, Cenovus adopted IFRS 15, *"Revenue From Contracts With Customers"* ("IFRS 15") replacing IAS 11, *"Construction Contracts",* IAS 18, *"Revenue"* and several revenue-related interpretations. The adoption of IFRS 15 did not have a material impact on our Consolidated Financial Statements.

Further information about changes to our accounting policies resulting from the adoption of IFRS 9 and IFRS 15 can be found in Note 3 to the interim Consolidated Financial Statements.

CONTROL ENVIRONMENT

Except for changes relating to the continuing integration of the Deep Basin Assets, as discussed below, there have been no changes to internal control over financial reporting ("ICFR") or disclosure controls and procedures ("DC&P") during the three months ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, ICFR or DC&P.

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

($ millions)	**Three Months Ended March 31, 2018**
Revenues	**224**
Operating Margin [1]	**99**
Net Earnings (Loss) [1]	**(83)**

As at	**March 31, 2018**
Current Assets	**653**
Non-Current Assets [1]	**6,023**
Current Liabilities	**367**
Non-Current Liabilities [1]	**501**

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

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 the remainder of 2018 will see continued commodity price volatility and market access constraints for Cenovus and our industry. We will continue to look for ways to increase our margins through strong operating performance and cost leadership, while focusing on 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 expect that transportation challenges faced by our industry will continue to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects in Canada to proceed as soon as possible.

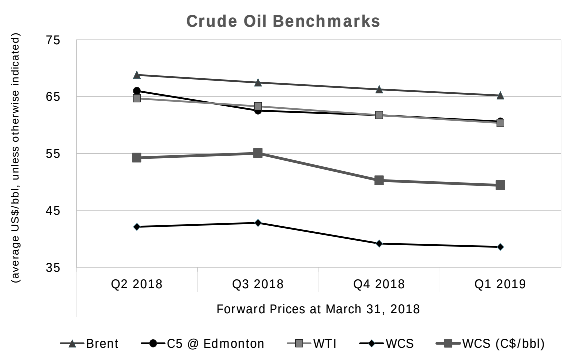
Through a continued focus on capital discipline and cost reductions, we have reduced the amount of capital needed to sustain our base business and expand our projects, which we believe will help to ensure our financial resilience.

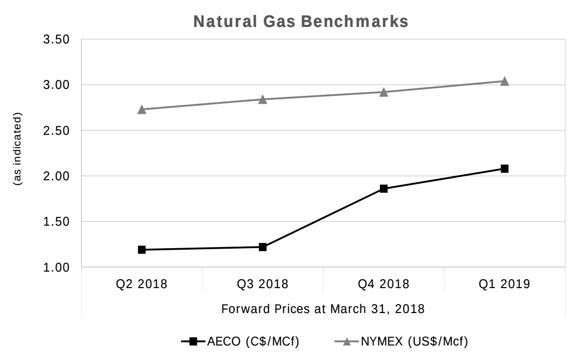
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and the pace of growth in global demand as influenced by macro-economic events;
- Overall, crude oil price volatility is expected to increase as inventories return to historical levels and prices remain relatively consistent;
- We anticipate the Brent-WTI differential will continue around current levels, after clearing most of the severe weather related impacts, and as additional pipeline capacity becomes available; and
- We expect that the WTI-WCS differential will remain under pressure until additional takeaway capabilities alleviates some of the expected production growth.

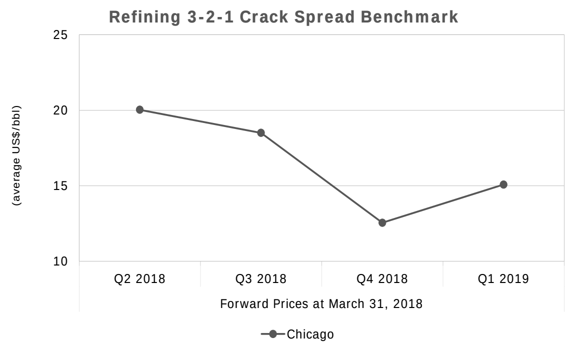


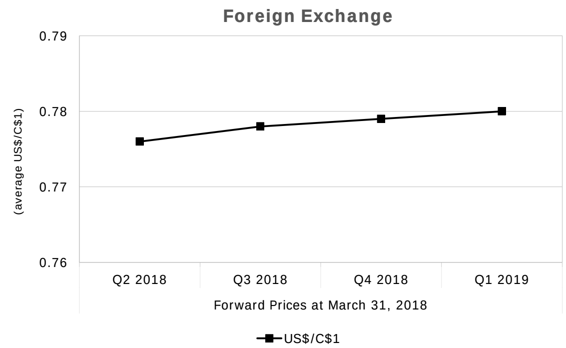


Natural gas prices are anticipated to remain challenged with supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain wide as supply pushes the limits of existing pipeline capacity.

Refining crack spreads will likely continue to fluctuate from current levels, adjusting for seasonal trends. The wide WTI-WCS differential will provide an incentive for U.S. Midwest refiners to process additional heavy crude oil volumes from Canada.

We expect the Canadian dollar to continue to be tied to a modest improvement in crude oil prices and the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise benchmark lending rates relative to each other. The Bank of Canada raised its benchmark lending rate twice in 2017 and again in early 2018, marking a notable shift for Canada towards a tighter monetary policy.





Our exposure to the light-heavy crude oil 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 the impact of swings in light-heavy crude oil 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 agreements – 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, including tidewater markets, as well as utilizing our crude-by-rail terminal to alleviate takeaway capacity constraints.

Natural gas and NGLs production associated with our Deep Basin Assets provide improved upstream integration for the fuel, solvent and blending requirements at our oil sands operations.

Key Priorities For 2018

Cost Reductions and Deleveraging

Our priorities in 2018 are to further reduce costs and deleverage our balance sheet, while maintaining capital discipline, in an effort to increase returns to shareholders. We remain focused on maintaining our financial resilience and flexibility while continuing to deliver safe and reliable operations, which remains a top priority.

Over the past three years, we have achieved significant improvements in our operating and sustaining capital costs. In 2018, we continue to target additional capital, operating and general and administrative cost reductions across Cenovus. We expect to realize additional savings through continued improvements in areas such as drilling performance, development planning and optimized scheduling of oil sands well start-ups. Our ability to drive structural and sustainable cost and margin improvements will further support our business plan, financial resilience and our ability to generate shareholder value.

We have already made some significant reductions to our non-rent general and administrative costs in 2018. In the first quarter of 2018, we substantially completed previously announced workforce reductions of approximately 15 percent from 2017 levels.

At March 31, 2018, through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $4.9 billion of liquidity. We continue to market for sale a package of non-core Deep Basin assets with production of approximately 15,000 BOE per day, and will look for further opportunities to streamline and high-grade our current portfolio of assets. We believe growth in cash flows, proceeds from additional asset divestitures and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target of less than 2.0 times.

Disciplined Capital Investment

In 2018, we anticipate capital investment to be between $1.5 billion and $1.7 billion. We plan to direct the majority of our 2018 capital budget towards sustaining oil sands production, while supporting ongoing construction at the Christina Lake phase G expansion and a targeted drilling program in the Deep Basin. With integration remaining an important part of our overall strategy, capital investment is also allocated for scheduled maintenance and reliability work at the Refineries.

Advance Focused Technology and Innovation to Achieve Margin Improvement

We have always believed that technology and innovation are differentiating factors in our industry. We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, 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 aim to complement our internal technology development efforts with external collaboration that will leverage our technology spend.

Market Access

Market access constraints for Canadian crude oil production 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, 2017 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 an average of three IQRE's January 1, 2018 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, 2017.

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 U.S. *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", "commitment", "can be", "pursue", "capacity", "could", "should", "will", "focus", "outlook", "potential", "priority", "aim", "on track", "schedule", "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; our strategy to increase cash flows through disciplined production growth from our industry-leading portfolio of oil sands and Deep Basin natural gas and liquids assets in western Canada; our focus on increasing our current share price and maximizing shareholder value through cost leadership and realizing the best margins for our products to help us maintain financial resilience and deliver sustainable dividend growth; our plan to achieve our strategy by drawing on the expertise of our people and leveraging our premium asset quality, executional excellence, value-added integration, focused innovation and trusted reputation; projections for 2018 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; our commitment to continue reducing debt, including our long term target Net Debt to Adjusted EBITDA ratio; our ability to satisfy payment obligations as they become due; priorities for and approach to capital investment decisions or capital allocation; planned capital expenditures, including the amount, timing and funding sources thereof; expected future production, including the timing, stability or growth thereof; expected reserves; capacities, including for projects, transportation and refining; expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including flexibility on timing of production and sales of inventory at later dates when pipeline capacity improves and crude oil differentials narrow; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost reductions and sustainability thereof; our priorities, including for 2018; 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; 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 Financial Statements; 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 and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future cost reductions; and projected growth and projected shareholder return.

Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas, natural gas liquids, condensate and refined products prices, light-heavy crude oil price differentials and other assumptions identified in Cenovus's 2018 guidance, available at cenovus.com; projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; achievement of further cost reductions and sustainability thereof; expected condensate prices; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to our share price and market capitalization over the long term; future narrowing of crude oil differentials; realization of expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including that we will be able to time production and sales of our inventory at later dates when pipeline capacity has improved and crude oil differentials have narrowed; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgements; future use and development of technology and associated expected future results; 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 applicable thereto; achievement of expected impacts of the Acquisition; successful completion of the 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 bitumen, crude oil, natural gas liquids, condensate and refined products 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 ability to access and implement all technology necessary to achieve expected future results; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

2018 guidance, as updated December 13, 2017, assumes: Brent prices of US$55.00/bbl, WTI prices of US$52.00/bbl; WCS of US$37.00/bbl; NYMEX natural gas prices of US$3.00/MMBtu; AECO natural gas prices of $2.20/GJ; Chicago 3-2-1 crack spread of US$15.00/bbl; and an exchange rate of $0.78 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: 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; possible failure to realize the expected impacts of our capacity to store within our oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline capacity and crude oil differentials have improved; 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; accuracy of our share price and market capitalization assumptions; 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 Net Debt to Adjusted EBITDA as well as 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, future production and future net revenue estimates; accuracy of our accounting estimates and judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; 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, materials, 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 bitumen and/or 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" are deemed to be forward looking information, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves 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 Management and Risk Factors" in this MD&A for the period ended December 31, 2017, available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	Barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
MMbbls	million barrels	Bcf	billion cubic feet
BOE	barrel of oil equivalent	MMBtu	million British thermal units
MMBOE	million barrel of oil equivalent	GJ	gigajoule
WTI	West Texas Intermediate	AECO	Alberta Energy Company
WCS	Western Canadian Select	NYMEX	New York Mercantile Exchange
CDB	Christina Dilbit Blend		
MSW	Mixed Sweet Blend		

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 From Continuing Operations

Continuing Upstream Financial Results

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended March 31, 2018 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	2,406	259	2,665	(1,274)	-	(63)	(14)	1,314
Royalties	58	35	93	-	-	-	-	93
Transportation and Blending	1,492	25	1,517	(1,274)	-	-	-	243
Operating	296	91	387	-	-	(63)	(12)	312
Netback	560	108	668	-	-	-	(2)	666
(Gain) Loss on Risk Management	454	9	463	-	-	-	-	463
Operating Margin	106	99	205	-	-	-	(2)	203

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended March 31, 2017 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	1,062	-	1,062	(478)	-	-	(5)	579
Royalties	27	-	27	-	-	-	-	27
Transportation and Blending	566	-	566	(478)	-	-	-	88
Operating	140	-	140	-	-	-	(1)	139
Netback	329	-	329	-	-	-	(4)	325
(Gain) Loss on Risk Management	77	-	77	-	-	-	-	77
Operating Margin	252	-	252	-	-	-	(4)	248

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.

Oil Sands

Three Months Ended March 31, 2018 ($ 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
Gross Sales	579	550	1,129	1	1,274	-	2	2,406
Royalties	47	11	58	-	-	-	-	58
Transportation and Blending	131	87	218	-	1,274	-	-	1,492
Operating	155	134	289	2	-	-	5	296
Netback	246	318	564	(1)	-	-	(3)	560
(Gain) Loss on Risk Management	200	254	454	-	-	-	-	454
Operating Margin	46	64	110	(1)	-	-	(3)	106

Three Months Ended March 31, 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
Gross Sales	287	290	577	2	478	-	5	1,062
Royalties	20	7	27	-	-	-	-	27
Transportation and Blending	55	33	88	-	478	-	-	566
Operating	71	65	136	3	-	-	1	140
Netback	141	185	326	(1)	-	-	4	329
(Gain) Loss on Risk Management	40	37	77	-	-	-	-	77
Operating Margin	101	148	249	(1)	-	-	4	252

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

Deep Basin

Three Months Ended March 31, 2018 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[2]	Per Interim Consolidated Financial Statements[1] Total Deep Basin
Gross Sales	247	12	259
Royalties	35	-	35
Transportation and Blending	25	-	25
Operating	84	7	91
Netback	103	5	108
(Gain) Loss on Risk Management	9	-	9
Operating Margin	94	5	99

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) Reflects operating margin from processing facility.

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

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended March 31, 2018	2017
Oil Sands		
Foster Creek	**163,911**	78,562
Christina Lake	**202,212**	89,919
Total Oil Sands Crude Oil	**366,123**	168,481
Natural Gas (MMcf per day)	**4**	15
Deep Basin		
Total Liquids	**35,479**	-
Natural Gas (MMcf per day)	**549**	-
Total Deep Basin (BOE per day)	**127,056**	-
Less: Internal Consumption [(1)] (MMcf per day)	**(322)**	-
Sales From Continuing Operations [(1)] (BOE per day)	**440,254**	170,981

(1) Less natural gas volumes used for internal consumption by the Oil Sands segment.