MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE PERIOD ENDED MARCH 31, 2019

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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 23, 2019, should be read in conjunction with our March 31, 2019 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements"), the December 31, 2018 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements") and the December 31, 2018 MD&A ("annual MD&A"). All of the information and statements contained in this MD&A are made as of April 23, 2019, 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 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, (which includes references to "dollar" or "$"), 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. We adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

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 7 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

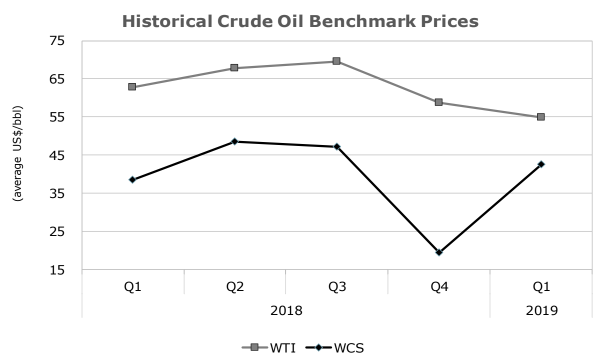
We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On March 31, 2019, we had an enterprise value of approximately $22 billion. Operations include oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged approximately 447,000 BOE per day for the three months ended March 31, 2019. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 375,000 gross barrels per day of crude oil feedstock into an average of 402,000 gross barrels per day of refined products in the three months ended March 31, 2019.

Our strategy is focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. We believe that maintaining a strong balance sheet will help Cenovus navigate through commodity price volatility and give us the flexibility to proceed with opportunities at all points in the price cycle. We aim to evaluate disciplined investment in our portfolio against dividend increases, share repurchases and maintaining the optimal debt level while retaining investment grade status. Our investment focus will be on areas where we believe we have the greatest competitive advantage. We plan to achieve our strategy by leveraging our strategic focus areas including oil sands, conventional oil and natural gas assets, marketing, transportation and refining portfolio, and our people.

For a description of our operations, refer to the Reportable Segments section of this MD&A.

QUARTERLY HIGHLIGHTS

Cenovus achieved very good operating and financial results in the first quarter of 2019. We continued to demonstrate capital discipline, cost leadership and made further progress on deleveraging the balance sheet.



Our upstream operational performance was very good during the quarter with production averaging 447,270 BOE per day restricted by the Government of Alberta mandatory curtailment program.

Market conditions in Alberta were significantly improved during the first quarter of 2019, particularly in comparison to the end of 2018. While Brent and West Texas Intermediate ("WTI") benchmark prices were slightly lower than both the first and fourth quarters of 2018, the narrowing of the differential between WTI and Western Canadian Select ("WCS") benchmark prices resulted in a significant improvement in the WCS benchmark crude oil prices. The WTI-WCS differential in the first quarter of 2019 narrowed to average US$12.37 per barrel from the record-highs in the fourth quarter of 2018, primarily as a result of the Government of Alberta curtailment limits. WCS benchmark crude oil averaged US$42.53 per barrel in the first quarter of 2019 compared with US$38.59 per barrel and US$19.39 per barrel in the first and fourth quarters of 2018, respectively. The increased WCS price along with lower cost of condensate due to lower condensate benchmark prices compared with the first quarter of 2018 positively impacted our financial results from our upstream assets.

Operational performance of our refining business was impacted by planned and unplanned maintenance at both the Wood River and Borger refineries (the "Refineries"). Our Refining and Marketing segment generated operating margin of $304 million due to improved crude oil runs and refined product output, a substantial increase in operating margin, from the first quarter of 2018 when the assets were undergoing major planned turnarounds.

In the first quarter of 2019, we:

- Produced 447,270 BOE per day with production volumes limited by the mandated curtailment;
- Achieved Cash from Operating Activities of $436 million and Adjusted Funds Flow of $1.0 billion, a significant increase from the first quarter of 2018; after capital spending of $317 million, generated Free Funds Flow of $731 million;
- Recorded Net Earnings from continuing operations of $110 million (2018 – Net Loss of $914 million);
- Earned an average companywide Netback from continuing operations of $26.64 per BOE, before realized hedging, up 59 percent from the first quarter of 2018 primarily due to narrower light-heavy crude oil differentials and the impact of lower condensate costs from purchases in the fourth quarter of 2018 resulting in stronger realized sales prices for our barrels;
- Repurchased US$449 million of our unsecured notes for cash of US$419 million, reducing net debt to $8.1 billion. In April 2019, we repurchased a further US$66 million of our unsecured notes for cash of US$63 million;

- Experienced reduced crude oil rates at Wood River due to a fire in a crude unit;
- Completed construction of the Christina Lake phase G expansion, which achieved first steam in January;
- Invested $317 million in capital compared with $524 million in 2018, reflecting our reduced capital investment program and continued focus on capital discipline; and
- Transported an average of 34,187 barrels per day of our volumes by rail.

OPERATING RESULTS

Our upstream operations performed very well in the first quarter of 2019. Crude oil production volumes were managed to the Government of Alberta mandated limits, producing an average of 347,800 barrels per day.

Upstream Production Volumes

	Three Months Ended March 31,		
	2019	**Percent Change**	2018
Continuing Operations			
Liquids (barrels per day)			
Oil Sands			
Foster Creek	**154,156**	**(2)**	157,390
Christina Lake	**188,824**	**(7)**	202,276
	342,980	**(5)**	359,666
Deep Basin			
Crude Oil	**4,820**	**(26)**	6,517
NGLs	**23,183**	**(20)**	28,962
	28,003	**(21)**	35,479
Liquids Production (barrels per day)	**370,983**	**(6)**	395,145
Natural Gas (MMcf per day)			
Oil Sands	**-**	**(100)**	4
Deep Basin (1)	**458**	**(17)**	549
	458	**(17)**	553
Production From Continuing Operations (BOE per day)	**447,270**	**(8)**	487,464
Production From Discontinued Operations (Conventional) (BOE per day)	**-**	**(100)**	1,097
Total Production (BOE per day)	**447,270**	**(8)**	488,561

(1) Includes production used for internal consumption by the Oil Sands segment of 320 MMcf per day for the three months ended March 31, 2019 (2018 – 322 MMcf per day).

Oil Sands production of 342,980 barrels per day decreased five percent compared with the first quarter of 2018 due to the production curtailments. In addition, in the first quarter of 2018, we voluntarily reduced production in response to market access constraints and discounted heavy oil pricing conditions.

Total production from our Deep Basin assets decreased in the first quarter of 2019 by 18 percent to 104,290 BOE per day compared with 2018 due to the divestiture of Cenovus Pipestone Partnership ("CPP") on September 6, 2018, lower sustaining capital investment, natural declines and downtime resulting from cold weather-related outages.

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.

($/BOE)	Three Months Ended March 31, 2019	2018 [2]
Sales Price	**46.66**	33.20
Royalties	**5.56**	2.34
Transportation and Blending	**6.42**	6.16
Operating Expenses	**8.03**	7.89
Production and Mineral Taxes	**0.01**	0.01
Netback Excluding Realized Risk Management [1]	**26.64**	16.80
Realized Risk Management Gain (Loss)	**0.35**	(11.69)
Netback Including Realized Risk Management [1]	**26.99**	5.11

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Our average Netback, excluding realized risk management gains and losses, increased 59 percent in the first quarter of 2019 due to higher realized sales prices and lower transportation and blending costs offset by lower sales volumes, higher royalties and higher per-unit operating costs. Higher royalties were driven by higher prices as a result of the mandated curtailment and our Christina Lake property achieving payout in the third quarter of 2018. The weakening of the Canadian dollar relative to the U.S. dollar compared with 2018 had a positive impact on our sales price of approximately $2.30 per BOE.

Refining and Marketing

Following major turnarounds in the first quarter of 2018 and a very good year of operations, effective January 1, 2019, the nameplate capacity at Wood River and Borger refineries increased to 482,000 gross barrels per day. Crude oil runs and refined product output in the first three months of 2019 increased year-over-year as major planned turnarounds were completed at both Refineries in the first quarter of 2018, partially offset by planned and unplanned maintenance at both Refineries in the first quarter of 2019, including a fire in a crude unit at the Wood River refinery.

	Three Months Ended March 31, 2019	Percent Change	2018
Crude Oil Capacity (Mbbls/d)	**482**	**5**	460
Crude Oil Runs [1] (Mbbls/d)	**375**	**7**	349
Heavy Crude Oil [1]	**143**	**(12)**	162
Refined Product [1] (Mbbls/d)	**402**	**9**	369
Crude Utilization [1] (percent)	**78**	**3**	76
Operating Margin [2] ($ millions)	**304**	**733**	(48)

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

In 2019, Operating Margin from the Refining and Marketing segment was $304 million, a $352 million increase from the first quarter of 2018, primarily due to lower operating expenses in 2019 as a result of major planned turnarounds at both Refineries in 2018, higher crude advantage from processing discounted WCS crude oil, a reduction in the cost of Renewable Identification Numbers ("RINs"), higher crude oil runs and refined product output partially offset by lower realized gasoline margins.

Further information on the changes in our production volumes, and other 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$/bbl, unless otherwise indicated)	Q1 2019	Percent Change	Q1 2018	Q4 2018
Brent				
Average	**63.88**	**(5)**	67.18	68.08
End of Period	**68.39**	**(3)**	70.27	53.80
WTI				
Average	**54.90**	**(13)**	62.87	58.81
End of Period	**60.14**	**(7)**	64.94	45.41
Average Differential Brent-WTI	**8.98**	**108**	4.31	9.27
WCS				
Average	**42.53**	**10**	38.59	19.39
Average (C$/bbl)	**56.58**	**16**	48.79	25.60
End of Period	**50.97**	**19**	42.88	30.69
Average Differential WTI-WCS	**12.37**	**(49)**	24.28	39.42
West Texas Sour (“WTS”)				
Average	**53.71**	**(13)**	61.46	52.38
End of Period	**61.09**	**-**	61.09	38.53
Average Differential WTI-WTS	**1.19**	**(16)**	1.41	6.43
Condensate (C5 @ Edmonton)				
Average	**50.50**	**(20)**	63.04	45.28
Average (C$/bbl)	**67.15**	**(16)**	79.70	59.74
Average Differential WTI-Condensate (Premium)/Discount	**4.40**	**(2,688)**	(0.17)	13.53
Average Differential WCS-Condensate (Premium)/Discount	**(7.97)**	**(67)**	(24.45)	(25.89)
Mixed Sweet Blend (“MSW” @ Edmonton)				
Average	**49.99**	**(12)**	56.98	32.51
Average (C$/bbl)	**66.48**	**(8)**	72.04	42.89
End of Period	**55.52**	**(8)**	60.63	44.19
Average Refined Product Prices				
Chicago Regular Unleaded Gasoline (“RUL”)	**64.15**	**(12)**	73.08	66.65
Chicago Ultra-low Sulphur Diesel (“ULSD”)	**77.10**	**(5)**	81.35	84.25
Refining Margin: Average 3-2-1 Crack Spreads (2)				
Chicago	**13.57**	**5**	12.96	13.43
Group 3	**14.80**	**(5)**	15.66	14.57
Average Natural Gas Prices				
AECO (3) (C$/Mcf)	**1.94**	**5**	1.85	1.90
NYMEX (US$/Mcf)	**3.15**	**5**	3.00	3.64
Basis Differential NYMEX-AECO (US$/Mcf)	**1.69**	**11**	1.52	2.19
Foreign Exchange Rate (US$ per C$1)				
Average	**0.752**	**(5)**	0.791	0.758
End of Period	**0.748**	**(4)**	0.776	0.733

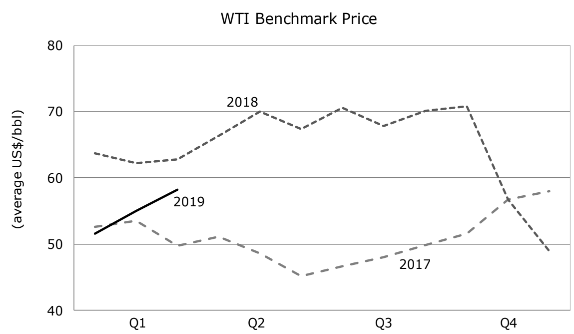
(1) These benchmark prices are not our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks tables in the Operating Results and Reportable Segments sections of this MD&A.
(2) The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.
(3) Alberta Energy Company (“AECO”) natural gas monthly index.

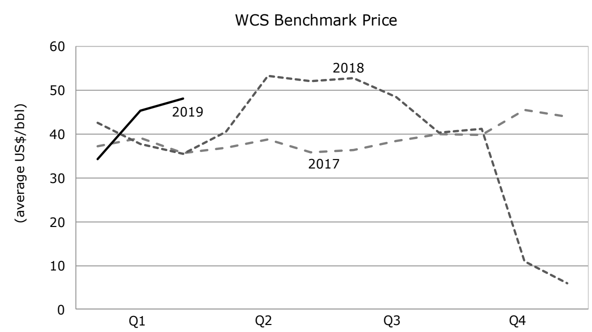
Crude Oil Benchmarks

The average Brent and WTI crude oil benchmark prices were lower in the first quarter of 2019, compared with both the first and fourth quarters of 2018. Benchmark prices improved over the course of the quarter as concerns of oversupply and weaker demand due to subsided U.S.-China trade tensions. In addition, in order to offset U.S. supply growth and balance the market, the Organization of Petroleum Exporting Countries (“OPEC”) cut production to support prices. Crude oil prices were further supported by turmoil in Venezuela which has reduced the country’s crude oil supply. The decrease of crude oil supply from Venezuela has reduced heavy crude oil imports causing WCS prices in the U.S. Gulf Coast to strengthen.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties. In the first quarter of 2019, the Brent-WTI differential increased compared with 2018 as a result of increasing U.S. supply exceeding pipeline takeaway capacity at Cushing, Oklahoma.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in the first three months of 2019 compared with the first and fourth quarters of 2018. Heavy oil differentials narrowed in the first quarter of 2019 in response to production curtailments mandated by the Government of Alberta to address record high differentials in the fourth quarter of 2018 and high levels of crude oil in storage. Decreased production due to mandatory curtailments resulted in upward movement of Alberta benchmark prices.





WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The differential between WTI and WTS benchmark prices narrowed in the first three months of 2019 since the end of 2018 and compared with the same period in 2018, due to additional pipeline capacity coming online, helping to debottleneck the Permian Basin as WTS makes its way to the U.S. Gulf Coast.

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 benchmark prices were discounted relative to WTI in the first three months of 2019 compared with a premium in the same period of 2018 due to high domestic inventories, as production curtailments were implemented, in addition to increasing domestic supply combined with higher than anticipated imports.

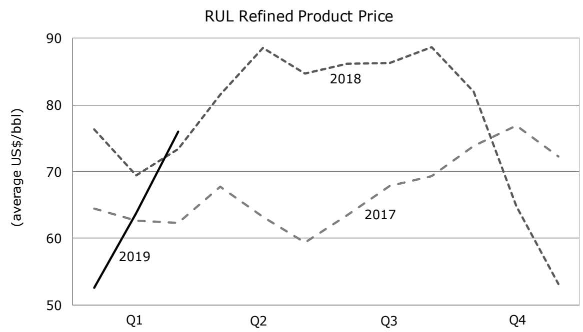
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin assets. The average MSW benchmark price declined in the first quarter of 2019 compared with 2018, consistent with the general decrease in average crude oil prices.

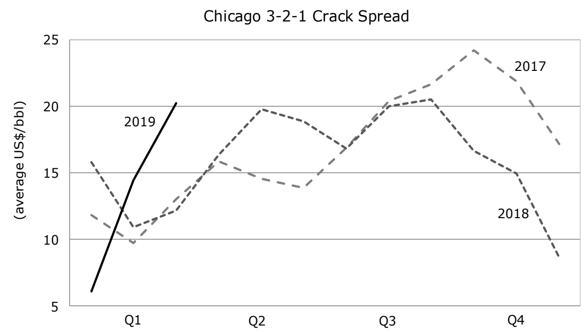
Refining Benchmarks

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 market crack spread. The 3-2-1 market 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 decreased in the first quarter of 2019 compared with the first quarter of 2018 primarily due to lower global crude oil prices. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by international prices, the strength of refining crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices. In the first three months of 2019, the Chicago 3-2-1 crack spread increased five percent, while the Group 3 crack spread decreased five percent from the same period of 2018.

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 strengthened during the first three months of 2019 compared with the first quarter of 2018 due to lower temperatures offset by higher natural gas supply in Alberta and constrained export capabilities. Average NYMEX prices also increased slightly compared with the first quarter of 2018 due to declining supply from the development of U.S. shale gas and natural gas associated with crude oil plays.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, 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 2019, the Canadian dollar weakened relative to the U.S. dollar on average, compared with the first three months of 2018, resulting in a positive impact of approximately $246 million on our revenues. The Canadian dollar as at March 31, 2019 compared with December 31, 2018 was stronger relative to the U.S. dollar, resulting in $215 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The impact of rising crude oil prices, mandatory production curtailments, higher refining throughput, and lower blending costs were the primary drivers of our financial results in the three months ended March 31, 2019. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	2019 Q1	2018 (5) Q4	Q3	Q2	Q1	2017 (5) Q4	Q3	Q2	Q1
Revenues	**5,004**	4,545	5,857	5,832	4,610	5,079	4,386	4,037	3,541
Operating Margin (1)									
From Continuing Operations	**1,239**	135	1,191	911	157	1,018	1,097	572	305
Total Operating Margin	**1,239**	132	1,192	938	169	1,088	1,214	731	450
Cash From Operating Activities									
From Continuing Operations	**436**	488	1,258	506	(134)	833	481	1,102	195
Total Cash From Operating Activities	**436**	485	1,259	533	(123)	900	592	1,239	328
Adjusted Funds Flow (2)									
From Continuing Operations	**1,048**	(33)	976	747	(53)	796	865	603	183
Total Adjusted Funds Flow	**1,048**	(36)	977	774	(41)	866	980	745	323
Operating Earnings (Loss) (2)									
From Continuing Operations	**69**	(1,670)	(41)	(292)	(752)	(533)	240	298	(39)
Per Share ($) (3)	**0.06**	(1.36)	(0.03)	(0.24)	(0.61)	(0.43)	0.20	0.27	(0.05)
Total Operating Earnings (Loss)	**69**	(1,672)	(42)	(272)	(743)	(514)	327	352	(39)
Per Share ($) (3)	**0.06**	(1.36)	(0.03)	(0.22)	(0.60)	(0.42)	0.27	0.32	(0.05)
Net Earnings (Loss)									
From Continuing Operations	**110**	(1,350)	(242)	(410)	(914)	(776)	275	2,558	211
Per Share ($) (3)	**0.09**	(1.10)	(0.20)	(0.33)	(0.74)	(0.63)	0.22	2.30	0.25
Total Net Earnings (Loss)	**110**	(1,356)	(241)	(418)	(654)	620	(82)	2,617	211
Per Share ($) (3)	**0.09**	(1.10)	(0.20)	(0.34)	(0.53)	0.50	(0.07)	2.35	0.25
Capital Investment (4)									
From Continuing Operations	**317**	276	271	294	522	557	396	277	225
Total Capital Investment	**317**	276	271	292	524	583	438	327	313
Dividends	**61**	62	61	62	60	61	62	61	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 7 of the interim Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Represented on a basic and diluted per share basis.
(4) Includes expenditures on property, plant and equipment ("PP&E"), Exploration and Evaluation ("E&E") assets and assets held for sale.
(5) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Revenues

($ millions)	
Revenues for the Three Months Ended March 31, 2018	**4,610**
Increase (Decrease) due to:	
Oil Sands	**(98)**
Deep Basin	**(18)**
Refining and Marketing	**457**
Corporate and Eliminations	**53**
Revenues for the Three Months Ended March 31, 2019	**5,004**

Upstream revenues decreased in the first quarter of 2019 compared with 2018 due to lower sales volumes and higher royalties, partially offset by higher realized pricing.

Refining and Marketing revenues increased 20 percent compared with the first quarter of 2018. Refining revenues increased due to an increase in refined product output partially offset by lower refined product pricing. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group increased in the first quarter of 2019 compared with 2018 due to an increase in crude oil and natural gas volumes and higher 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

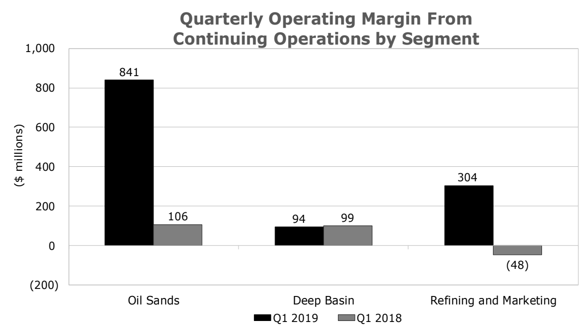
Operating Margin is an additional subtotal found in Notes 1 and 7 of the interim Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, 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)	**2019**	2018 (1)
Revenues	**5,145**	4,804
(Add) Deduct:		
Purchased Product	**2,163**	1,957
Transportation and Blending	**1,166**	1,517
Operating Expenses	**596**	705
Realized (Gain) Loss on Risk Management Activities	**(19)**	468
Operating Margin From Continuing Operations	**1,239**	157
Conventional (Discontinued Operations)	**-**	12
Total Operating Margin	**1,239**	169

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating Margin from continuing operations increased in the first three months of 2019 compared with 2018 primarily due to:

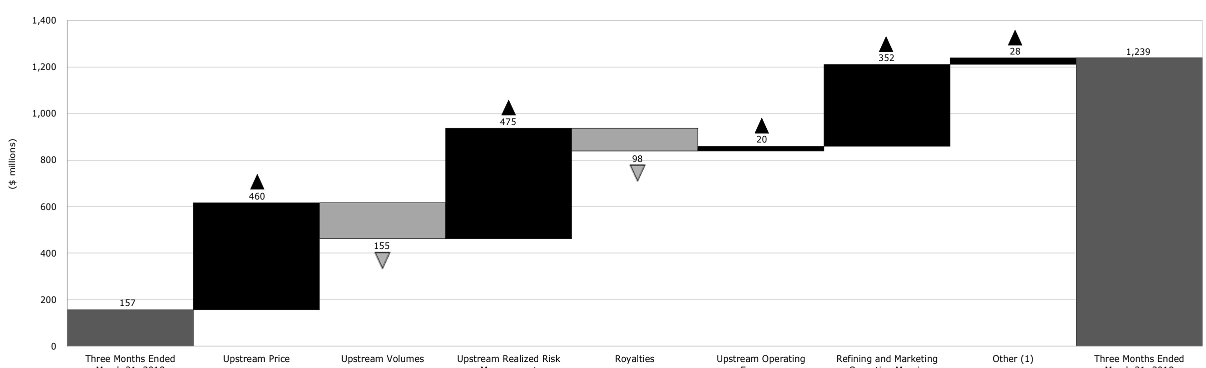
- An increase in our average liquids and natural gas sales prices;
- Higher Operating Margin from our Refining and Marketing segment due to lower operating expenses, higher crude advantage and higher crude oil rates;
- A decrease in upstream operating expenses; and
- Realized risk management gains of $19 million (2018 – losses of $468 million).



These increases in Operating Margin were partially offset by:

- Lower sales volumes; and
- Higher royalties primarily due to Christina Lake achieving payout in August 2018 and higher revenues at both Foster Creek and Christina Lake.

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 accounts receivable, inventory, income tax receivable, accounts payable and income tax payable. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

Total Cash From Operating Activities and Adjusted Funds Flow

($ millions)	Three Months Ended March 31, 2019	2018 [2]
Cash From Operating Activities [1]	**436**	(123)
(Add) Deduct:		
Net Change in Other Assets and Liabilities	**(21)**	(18)
Net Change in Non-Cash Working Capital	**(591)**	(64)
Adjusted Funds Flow [1]	**1,048**	(41)

(1) Includes results from our Conventional segment, which has been classified as a discontinued operation.
(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Cash From Operating Activities and Adjusted Funds Flow were higher compared with the first quarter of 2018 due to higher Operating Margin, as discussed above, lower general and administrative costs primarily due to $43 million of severance costs incurred in the first quarter of 2018, partially offset by an increase in current income tax expense.

The change in non-cash working capital in the first quarter of 2019 was due to an increase in accounts receivable from higher blend prices for crude oil and higher inventory due to increased product volumes and costs, partially offset by an increase in accounts payable. For the three months ended March 31, 2018, the change in non-cash working capital was primarily due to a decrease in accounts payable and income tax payable, partially offset by a decrease in accounts receivable.

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, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

($ millions)	Three Months Ended March 31, 2019	2018 [3]
Earnings (Loss) From Continuing Operations, Before Income Tax	**157**	(1,072)
Add (Deduct):		
Unrealized Risk Management (Gain) Loss [1]	**236**	(139)
Non-Operating Unrealized Foreign Exchange (Gain) Loss [2]	**(209)**	264
(Gain) Loss on Divestiture of Assets	**5**	-
Other	**-**	(1)
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**189**	(948)
Income Tax Expense (Recovery)	**120**	(196)
Operating Earnings (Loss) From Continuing Operations	**69**	(752)
Operating Earnings (Loss) From Discontinued Operations	**-**	9
Total Operating Earnings (Loss)	**69**	(743)

(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.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating Earnings from continuing operations increased in the first quarter of 2019 compared with 2018 primarily due to higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above, lower depreciation, depletion and amortization ("DD&A"), a lower provision for onerous contracts, partially offset by a remeasurement loss of $263 million on the contingent payment compared with a loss of $117 million in 2018, higher non-cash long-term incentive costs and non-operating realized foreign exchange loss of $28 million compared with a gain of $3 million in 2018.

Net Earnings (Loss)

($ millions)	
Net Earnings (Loss) From Continuing Operations, for the Three Months Ended March 31, 2018 [(1)]	**(914)**
Increase (Decrease) due to:	
Operating Margin From Continuing Operations	**1,082**
Corporate and Eliminations:	
Unrealized Risk Management Gain (Loss)	**(375)**
Unrealized Foreign Exchange Gain (Loss)	**511**
Re-measurement of Contingent Payment	**(146)**
Gain (Loss) on Divestiture of Assets	**(5)**
Expenses [(2)]	**96**
DD&A	**69**
Exploration Expense	**(3)**
Income Tax Recovery (Expense)	**(205)**
Net Earnings (Loss) From Continuing Operations, for the Three Months Ended March 31, 2019	**110**

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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

Net Earnings of $110 million from continuing operations in the first quarter of 2019 increased primarily due to:

- Higher Operating Earnings, as discussed above; and
- Non-operating foreign exchange gains of $209 million compared with losses of $264 million in 2018.

These increases to our Net Earnings (Loss) from continuing operations in 2019 were partially offset by unrealized risk management losses of $236 million compared with gains of $139 million in 2018, and a deferred income tax expense of $41 million compared with a recovery of $104 million in 2018.

Total Capital Investment

	Three Months Ended March 31,	
($ millions)	**2019**	2018 [(2)]
Oil Sands	**214**	318
Deep Basin	**14**	145
Refining and Marketing	**55**	53
Corporate and Eliminations	**34**	6
Capital Investment - Continuing Operations	**317**	522
Conventional (Discontinued Operations)	**-**	2
Total Capital Investment [(1)]	**317**	524

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

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Capital investment in the first quarter of 2019 decreased compared with 2018, reflecting our reduced capital investment program, continued focus on capital discipline, lower Christina Lake phase G spend as the project was completed in March 2019 and a smaller sustaining and re-drill program. Oil Sands capital investment focused on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells; and the completion of Christina Lake phase G construction. The majority of the capital investment within Deep Basin related to spending on infrastructure, equipping and pad tie-in activity.

Refining and Marketing capital investment increased in the first quarter of 2019 due to unplanned maintenance related to the fire at the Wood River refinery offset by the timing of capital spend for Borger compared with the first quarter of 2018.

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. In addition to our commitment to reduce our debt, we are looking for opportunities to streamline our asset portfolio and 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, further deleveraging, 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.

	Three Months Ended March 31,	
($ millions)	**2019**	2018 (3)
Adjusted Funds Flow (1)	**1,048**	(41)
Total Capital Investment (1)	**317**	524
Free Funds Flow (1) (2)	**731**	(565)
Cash Dividends	**61**	60
	670	(625)

(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.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

In 2019 we expect to spend between $1.2 billion and $1.4 billion, consistent with our initial 2019 guidance dated December 10, 2018. Our updated guidance dated April 23, 2019 is available on our website at cenovus.com.

We expect our capital investment and cash dividends for 2019 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 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.

Deep Basin, which includes approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities.

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. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.

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, transloading services provided to the Oil Sands segment by the Company's rail terminal, 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.

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)	**2019**	2018
Oil Sands	**2,250**	2,348
Deep Basin	**206**	224
Refining and Marketing	**2,689**	2,232
Corporate and Eliminations	**(141)**	(194)
	5,004	4,610

OIL SANDS

Significant developments in our Oil Sands segment for the first quarter of 2019 compared with 2018 include:

- Managing total production to mandated curtailment requirements;
- Earning crude oil netbacks of $27.88 per barrel, excluding realized risk management activities, a 63 percent increase compared with 2018;
- Oil sands per-unit operating costs of $9.06 per barrel, a three percent increase from 2018 mainly due to reduced sales volumes and higher fuel costs due to higher natural gas prices;
- Investing $214 million, composed of costs to complete Christina Lake phase G, which was completed ahead of schedule and below the anticipated capital required, and sustaining capital. First steam at Christina Lake phase G was achieved in January. Start-up of the Christina Lake phase G well pad production will depend on when mandatory production curtailments are lifted and if there is sustained improvement in market access and heavy oil benchmark prices; and
- Generating Operating Margin of $841 million, an increase of $735 million due to higher average realized sales prices, decreased transportation and blending costs, and realized risk management gains of $12 million compared with losses of $454 million in 2018 partially offset by higher royalties and lower sales volumes.

Oil Sands – Crude Oil

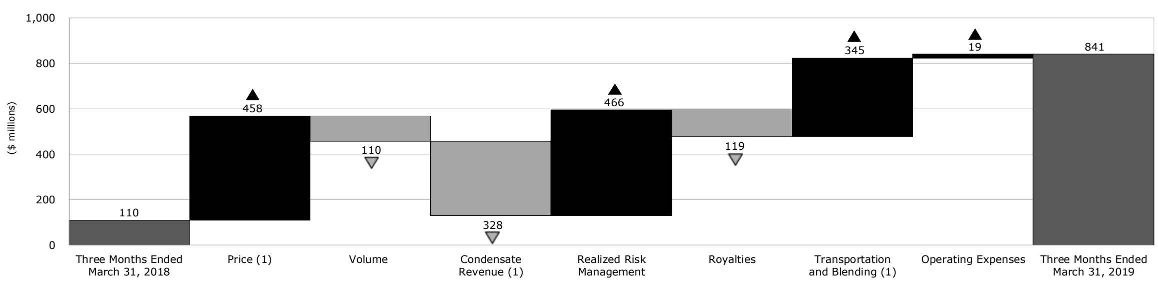
Financial Results

	Three Months Ended March 31,	
($ millions)	**2019**	2018 (1) (2)
Gross Sales	**2,423**	2,403
Less: Royalties	**177**	58
Revenues	**2,246**	2,345
Expenses		
Transportation and Blending	**1,147**	1,492
Operating	**270**	289
(Gain) Loss on Risk Management	**(12)**	454
Operating Margin	**841**	110
Capital Investment	**214**	317
Operating Margin Net of Related Capital Investment	**627**	(207)

(1) Excludes results from the Athabasca natural gas property.

(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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 2019, our average realized crude oil sales price increased to $49.67 per barrel (2018 - $34.27 per barrel). While WTI benchmark prices decreased from the first quarter of 2018, the narrowing of the heavy oil differential increased our realized crude oil price. The WTI-WCS differential narrowed to a discount of US$12.37 per barrel (2018 – US$24.28 per barrel) and the WCS-Christina Dilbit Blend ("CDB") differential narrowed to a discount of US$1.78 per barrel (2018 – discount of US$2.68 per barrel).

Our realized 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 a positive impact on our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

(barrels per day)	Three Months Ended March 31, 2019	Percent Change	2018
Foster Creek	**154,156**	**(2)**	157,390
Christina Lake	**188,824**	**(7)**	202,276
	342,980	**(5)**	359,666

Production levels in the first quarter of 2019 were impacted by the government curtailment orders. In the first quarter of 2018, we voluntarily reduced production levels in response to market access constraints and discounted heavy oil pricing.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential in 2019, the proportion of the cost of condensate recovered increased. The total amount of condensate used decreased as a result of lower sales 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.

Royalties for 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.

Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. Royalties for 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 revenues less diluent costs and transportation costs. Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects with our Christina Lake property achieving payout in the third quarter of 2018.

Effective Royalty Rates

(percent)	Three Months Ended March 31, 2019	2018
Foster Creek	**10.9**	10.4
Christina Lake	**17.4**	2.3

Royalties increased $119 million in the first quarter of 2019 compared with 2018. Royalties at Foster Creek and Christina Lake increased primarily due to Christina Lake achieving project payout in August 2018 and higher realized sales prices, partially offset by lower annual average WTI benchmark pricing (which determines the royalty rate) and lower sales volumes.

Expenses

Transportation and Blending

Transportation and blending costs decreased $345 million compared with the first quarter of 2018. Blending costs decreased primarily from lower priced condensate in the first quarter of 2019 compared with 2018 and due to a decline in condensate volumes required for our decreased production.

Per-unit Transportation Expenses

At Foster Creek, transportation costs increased $0.46 per barrel due to higher rail transportation partially offset by IFRS 16 adoption impacts and decreased sales volumes. Christina Lake transportation costs of $4.46 per barrel were seven percent lower relative to 2018 due to decreased sales volumes and IFRS 16 adoption impacts, partially offset by higher rail costs.

Operating

Primary drivers of our operating expenses in the first quarter of 2019 were fuel, workforce costs, chemical costs, repairs and maintenance, and workovers. Total operating expenses decreased $19 million primarily due to decreased workforce costs, lower well servicing costs, fewer pump changes and lower chemical costs due to lower oil production. In addition, fuel costs increased due to higher natural gas prices and consumption as a result of continuing to target maximum reservoir steam injection and pressure.

Per-unit Operating Expenses

($/bbl)	Three Months Ended March 31, 2019	Percent Change	2018 [1]
Foster Creek			
Fuel	**3.13**	**13**	2.77
Non-fuel	**7.31**	**(6)**	7.74
Total	**10.44**	**(1)**	10.51
Christina Lake			
Fuel	**2.80**	**19**	2.35
Non-fuel	**5.04**	**-**	5.03
Total	**7.84**	**6**	7.38
Total	**9.06**	**3**	8.78

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

At Foster Creek and Christina Lake, per-barrel fuel costs increased in the first quarter of 2019 primarily due to lower sales volumes and higher natural gas prices and consumption. In addition, Foster Creek per-barrel non-fuel operating expenses decreased primarily due to lower workforce spending, fewer workovers, and lower repairs and maintenance partially offset by lower sales volumes. At Christina Lake, per-barrel non-fuel operating expenses were comparable with 2018, with reductions in workforce and chemicals offset by lower sales volumes.

Netbacks [1]

	Foster Creek		Christina Lake	
	Three Months Ended March 31,			
($/bbl)	**2019**	2018 [2]	**2019**	2018 [2]
Sales Price	**51.99**	39.29	**47.63**	30.20
Royalties	**4.45**	3.17	**7.30**	0.59
Transportation and Blending	**9.39**	8.93	**4.46**	4.78
Operating Expenses	**10.44**	10.51	**7.84**	7.38
Netback Excluding Realized Risk Management	**27.71**	16.68	**28.03**	17.45
Realized Risk Management Gain (Loss)	**0.39**	(13.53)	**0.42**	(13.99)
Netback Including Realized Risk Management	**28.10**	3.15	**28.45**	3.46

(1) Netbacks reflect our operating margin on a per-barrel basis of unblended crude oil.
(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Risk Management

Risk management positions in the first quarter of 2019 resulted in realized gains of $12 million (2018 – realized losses of $454 million), consistent with our contract prices exceeding average benchmark prices.

Oil Sands – Capital Investment

($ millions)	Three Months Ended March 31, 2019	2018 [3]
Foster Creek	**71**	139
Christina Lake	**121**	164
	192	303
Other [1]	**22**	15
Capital Investment [2]	**214**	318

(1) Includes new resource plays, Narrows Lake, Telephone Lake and Athabasca natural gas.
(2) Includes expenditures on PP&E and E&E assets.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Oil Sands capital investment of $214 million focused on a smaller well and re-drill program and completion of the Christina Lake phase G construction. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells. Christina Lake capital investment focused on the completion of the phase G construction, sustaining capital related to existing production and stratigraphic test wells.

Drilling Activity

Three Months Ended March 31,	Gross Stratigraphic Test Wells		Gross Production Wells [1]	
	2019	2018	**2019**	2018
Foster Creek	**14**	43	**-**	8
Christina Lake	**18**	63	**5**	14
	32	106	**5**	22
Other	**14**	2	**-**	-
	46	108	**5**	22

(1) Steam-assisted gravity drainage 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 2019 is forecast to be between $250 million and $300 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 2019 is forecast to be between $425 million and $475 million, focused on sustaining capital. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, was completed at the end of the first quarter of 2019 with first steam achieved. We have flexibility on when we ramp-up production from Christina Lake phase G. We will take into consideration whether mandated production curtailments have been lifted and if there is sustained improvement in market access and heavy oil benchmark prices.

In 2019, we plan to spend a minimal amount of capital on Foster Creek phase H, Christina Lake phase H and Narrows Lake to continue to advance each one to sanction-ready status.

In 2019, our Technology and other capital investment, forecast to be between $55 million and $65 million, relates to advancing key strategic initiatives that are expected to provide both cost and environmental benefits. This includes ongoing work on solvents, partial upgrading and advancing our new oil sands facility design. Guidance dated April 23, 2019 is available on our website at cenovus.com.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over total proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with estimated 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. Our depletion rates resulted in a total average rate ranging between $9.16 per BOE to $11.97 per BOE.

We depreciate our right-of-use ("ROU") assets on a straight-line basis over the shorter of the estimated useful life or the lease term.

Amounts related to assets under construction and assets held for sale, which would be included in the total upstream cost base noted above and would have proved reserves attributed to them, are not depleted. Property specific rates will exclude upstream assets and ROU assets from the adoption of IFRS 16, that are depreciated on a straight-line basis. Further information on our accounting policy for DD&A is included in our notes to the December 31, 2018 Consolidated Financial Statements and the interim Consolidated Financial Statements.

Future development costs increased due to additional capital required to improve recovery performance and develop thin pay volumes at Christina Lake and Foster Creek, as well as an increase in maintenance capital at Foster Creek that increased our depletion rates.

In the first quarter of 2019, Oil Sands DD&A of $369 million increased $7 million compared with the same period in 2018 due to the recognition of ROU assets and an increase in the average depletion rate compared with 2018, partially offset by lower sales volumes. Our depletion rate in 2019 was approximately $11.20 per BOE (2018 - $10.65 per BOE).

DEEP BASIN

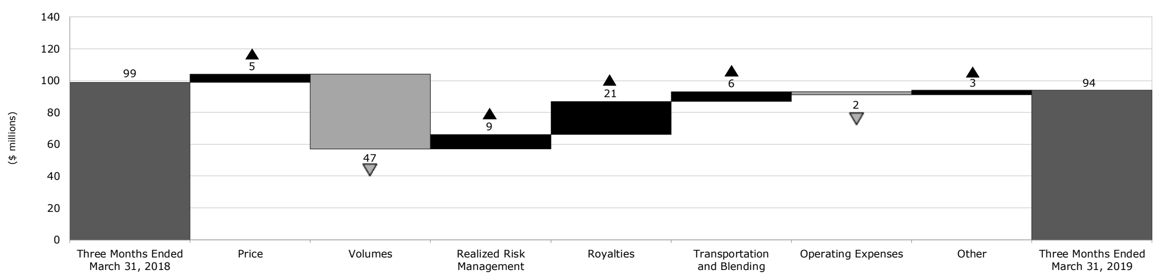
Significant developments in our Deep Basin segment for the first quarter of 2019 compared with 2018 include:

- Producing 104,290 BOE per day, an 18 percent decrease from 2018 due to the divestiture of CPP and lower capital investment;
- Investing capital of $14 million, focused on infrastructure, equipping and pad tie-in activity;
- Earning a netback of $9.10 per BOE, excluding realized risk management activities; and
- Generating Operating Margin of $94 million, a decrease of $5 million due to lower volumes and higher operating costs, partially offset by lower royalties, realized risk management activities, transportation and blending costs and higher sales prices.

Financial Results

($ millions)	Three Months Ended March 31, 2019	2018
Gross Sales	**220**	259
Less: Royalties	**14**	35
Revenues	**206**	224
Expenses		
Transportation and Blending	**19**	25
Operating	**93**	91
(Gain) Loss on Risk Management	**-**	9
Operating Margin	**94**	99
Capital Investment	**14**	145
Operating Margin Net of Related Capital Investment	**80**	(46)

Operating Margin Variance



Revenues

Price

	Three Months Ended March 31, 2019	2018
Light and Medium Oil ($/bbl)	**59.79**	67.30
NGLs ($/bbl)	**28.53**	37.73
Natural Gas ($/mcf)	**2.89**	2.23
Total Oil Equivalent ($/BOE)	**21.86**	21.68

In the first quarter of 2019, revenues include $15 million of processing fee revenue related to our interests in natural gas processing facilities (2018 – $12 million). We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	Three Months Ended March 31, 2019	2018
Liquids		
Crude Oil (barrels per day)	**4,820**	6,517
NGLs (barrels per day)	**23,183**	28,962
	28,003	35,479
Natural Gas (MMcf per day)	**458**	549
Total Production (BOE/d)	**104,290**	127,056
Natural Gas Production (percentage of total)	**73**	72
Liquids Production (percentage of total)	**27**	28

In the first quarter of 2019, production from the Deep Basin assets was 104,290 BOE per day, an 18 percent decrease from 2018 due to the divestiture of CPP, lower capital investment, natural declines and downtime resulting from cold weather-related outages.

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 Government of Alberta released a new Royalty Regime, Alberta's Modernized Royalty Framework ("MRF"), which applies to all producing wells drilled 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 2019, our effective royalty rate was 11.7 percent for liquids and 3.4 percent for natural gas (2018 – 23.1 percent for liquids and 6.0 percent for natural gas). The decline in rates were due to prior period crown adjustments and production decreases.

Expenses

Transportation

Transportation costs averaged $2.06 per BOE in the first quarter of 2019 compared with $2.21 per BOE in 2018. Our transportation costs reflect 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, property tax and lease costs and processing fees. Operating costs averaged $9.24 per BOE in the first quarter of 2019 (2018 - $7.36 per BOE). The increase in per-unit operating costs were driven by lower sales volumes due to the divestiture of CPP, higher property tax and lease costs and higher electricity rates, partially offset by lower repairs and maintenance activity.

Netbacks

	Three Months Ended March 31,	
($/BOE)	**2019**	2018
Sales Price	**21.86**	21.68
Royalties	**1.43**	3.09
Transportation and Blending	**2.06**	2.21
Operating Expenses	**9.24**	7.36
Production and Mineral Taxes	**0.03**	0.03
Netback Excluding Realized Risk Management	**9.10**	8.99
Realized Risk Management Gain (Loss)	**(0.01)**	(0.80)
Netback Including Realized Risk Management	**9.09**	8.19

Risk Management

Risk management activities in the first quarter of 2019 were minimal (2018 – realized losses of $9 million).

Deep Basin – Capital Investment

In the first three months of 2019, we focused on investing capital in infrastructure, equipping and tie-in activity. We invested $14 million in the first three months compared with $145 million in 2018. In 2018, we focused on investment in a horizontal well drilling program as well as facilities and infrastructure to support production growth in our core development areas.

($ millions)	Three Months Ended March 31, 2019	2018
Drilling and Completions	**1**	94
Facilities	**5**	35
Other	**8**	16
Capital Investment (1)	**14**	145

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

Drilling Activity

The following table summarizes Cenovus's net well activity:

	Three Months Ended March 31, 2019			Three Months Ended March 31, 2018		
(net wells, unless otherwise stated)	**Drilled (1)**	**Completed**	**Tied-in**	Drilled (1)	Completed	Tied-in
Elmworth-Wapiti	**-**	**-**	**-**	4	6	9
Kaybob-Edson	**-**	**-**	**-**	7	8	4
Clearwater	**-**	**-**	**-**	3	2	4
Total	**-**	**-**	**-**	14	16	17

(1) There were no wells drilled in the first quarter of 2019 (2018 – 12 operated net horizontal wells and two non-operated net horizontal wells).

Future Capital Investment

Our 2019 Deep Basin capital investment is forecast to be between $50 million and $75 million in 2019.

We continue to take a disciplined approach to the development of our Deep Basin assets considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. Management is committed to developing this significant resource; however, at a much slower pace of development. Guidance dated April 23, 2019 is available 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 $9.15 per BOE in the first quarter of 2019 (2018 – $10.40 per BOE).

Deep Basin DD&A was $86 million in the first quarter of 2019 (2018 – $204 million). The decrease was due to the divestiture of CPP and a lower depletion rate. In the first quarter of 2018 we recorded an impairment loss of $100 million on the Clearwater cash-generating unit.

REFINING AND MARKETING

Significant developments in our Refining and Marketing segment for the first quarter of 2019 compared with 2018 include:

- Increasing refinery processing capacity effective January 1, 2019 to 482,000 gross barrels per day of crude oil;
- Achieving crude oil runs averaging 375,000 barrels per day, a seven percent improvement from the first quarter of 2018. Crude oil rates at Wood River in 2019 were impacted by planned maintenance and a fire in a crude unit;
- Increasing total rail volumes loaded at the Bruderheim Energy Terminal, averaging 52,833 barrels per day in the first quarter of 2019, compared with an average of 16,207 barrels per day loaded in 2018; and
- Generating Operating Margin of $304 million, an increase of $352 million compared with 2018.

Refinery Operations [1]

	Three Months Ended March 31, 2019	2018
Crude Oil Capacity (Mbbls/d)	**482**	460
Crude Oil Runs (Mbbls/d)	**375**	349
Heavy Crude Oil	**143**	162
Light/Medium	**232**	187
Refined Products (Mbbls/d)	**402**	369
Gasoline	**213**	189
Distillate	**135**	120
Other	**54**	60
Crude Utilization (percent)	**78**	76

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.

On a 100 percent basis, the Refineries had a total processing capacity re-rated on January 1, 2019 to 482,000 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 both WCS and WTS 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.

Total crude oil runs and refined product output in the first three months of 2019 increased compared with 2018 as major planned turnarounds were underway at the Refineries in the first quarter of 2018. The increased rates in 2019 were partially offset by planned maintenance and unplanned outages at both Refineries including a fire at Wood River.

Financial Results

($ millions)	Three Months Ended March 31, 2019	2018 [1]
Revenues	**2,689**	2,232
Purchased Product	**2,163**	1,957
Gross Margin	**526**	275
Expenses		
Operating	**229**	318
(Gain) Loss on Risk Management	**(7)**	5
Operating Margin	**304**	(48)
Capital Investment	**55**	53
Operating Margin Net of Related Capital Investment	**249**	(101)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

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 2019, Refining and Marketing gross margin increased relative to the first quarter of 2018, primarily due to higher crude advantage from processing discounted WCS crude oil, lower RINs costs, higher crude oil runs and refined product output, partially offset by lower realized gasoline margins. Our gross margin was positively impacted by approximately $25 million due to the weakening of the Canadian dollar relative to the U.S. dollar in 2019 compared with the first quarter of 2018.

In the first quarter of 2019, the cost of RINs was $26 million compared with $47 million in 2018. RIN costs declined, despite higher volume obligations in 2019, due primarily to the decrease in RINs benchmark prices as a result of small refiners being granted exemptions from volume obligations.

Operating Expense

Primary drivers of operating expenses in the first quarter of 2019 were labour, maintenance and utilities. Operating expenses decreased compared with the first quarter of 2018 due to planned turnaround costs in 2018, partially offset by costs associated with the unplanned outages in 2019.

Refining and Marketing – Capital Investment

($ millions)	Three Months Ended March 31, 2019	2018 (1)
Wood River Refinery	**23**	35
Borger Refinery	**26**	17
Marketing	**6**	1
Capital Investment	**55**	53

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Capital expenditures in the first quarter of 2019 focused primarily on capital maintenance and reliability work, as well as yield improvement projects.

In 2019, we expect to invest between $240 million and $275 million and will continue to focus on capital maintenance, reliability work and yield improvement projects. Our guidance dated April 23, 2019 is available 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 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Refining and Marketing DD&A was $80 million in the first quarter of 2019 compared with $54 million in 2018 due to the adoption of IFRS 16.

CORPORATE AND ELIMINATIONS

In the three months ended March 31, 2019, our risk management activities resulted in:

- Unrealized risk management losses of $236 million (2018 – gains of $139 million);
- Realized risk management losses of $1 million on interest rate swaps (2018 – $nil); and
- Realized risk management gains of $1 million on foreign exchange contracts (2018 – loss of $1 million).

($ millions)	Three Months Ended March 31, 2019	2018 (1)
General and Administrative	**72**	120
Onerous Contract Provisions	**(1)**	59
Finance Costs	**124**	150
Interest Income	**(2)**	(3)
Foreign Exchange (Gain) Loss, Net	**(198)**	277
Re-measurement of Contingent Payment	**263**	117
Research Costs	**4**	12
(Gain) Loss on Divestiture of Assets	**5**	-
Other (Income) Loss, Net	**9**	(2)
	276	730

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Expenses

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs and office rent. General and administrative costs decreased by $48 million in the first three months of 2019, primarily driven by lower headcount in 2019, minimal severance costs in 2019 compared with $43 million in 2018, lower rent costs due to the adoption of IFRS 16, partially offset by increases in long-term employee incentive costs compared with the first quarter of 2018.

Onerous Contract Provisions

In 2019, onerous contract provisions are composed of non-lease components of real estate contracts which consist of operating costs and unreserved parking. In 2018, onerous contract provisions included the lease components of base rent and reserved parking as well as the non-lease components.

In the first quarter of 2019, we recorded a non-cash recovery for onerous contracts of $1 million due to an update in the underlying assumptions compared with an expense of $59 million in 2018 for certain Calgary office space in excess of current and near-term requirements.

Finance Costs

Finance costs include interest expense on our short-term borrowings, long-term debt, and lease liability (as at January 1, 2019), as well as the discount on redemption of long-term debt and unwinding of the discount on decommissioning liabilities. Finance costs decreased by $26 million in the first quarter of 2019 compared with 2018 due to the reduction of total debt and a gain in 2019 of $32 million on the repurchase of unsecured notes partially offset by an increase in interest of $19 million related to lease liabilities from the adoption of IFRS 16.

The weighted average interest rate on outstanding debt for the first quarter of 2019 was 5.1 percent (2018 - 5.1 percent).

Foreign Exchange

	Three Months Ended March 31,	
($ millions)	**2019**	2018
Unrealized Foreign Exchange (Gain) Loss	**(229)**	282
Realized Foreign Exchange (Gain) Loss	**31**	(5)
	(198)	277

In the first quarter of 2019, unrealized foreign exchange gains of $229 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at March 31, 2019 was two percent stronger compared with December 31, 2018, creating unrealized gains. Realized foreign exchange losses of $31 million was recorded primarily as a result of the unsecured notes repurchased in the first quarter of 2019.

Re-measurement of Contingent Payment

Related to oil sands production, Cenovus has agreed to make quarterly payments to ConocoPhillips Company and certain of its subsidiaries ("ConocoPhillips") during the five years subsequent to the closing date of the acquisition of Deep Basin assets from ConocoPhillips in conjunction with their 50 percent interest in the FCCL Partnership on May 17, 2017 (the "Acquisition") for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. The quarterly payment is $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 $370 million as at March 31, 2019 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, 2019, a non-cash re-measurement loss of $263 million was recorded. For the three months ended March 31, 2019, $25 million is payable under this agreement.

Average WCS forward pricing for the remaining term of the contingent payment is C$50.15 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$45.50 per barrel and C$65.20 per barrel.

Corporate – Capital Investment

Capital expenditures of $34 million in the first quarter of 2019 focused primarily on the build-out of office space at Brookfield Place compared with $6 million in the same period of 2018.

In 2019, we expect to invest between $150 million and $175 million, the majority of which is for the build-out of office space at Brookfield Place. Guidance dated April 23, 2019 is available on our website at cenovus.com.

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. ROU assets (real estate assets) are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in the first quarter of 2019 was $31 million (2018 – $15 million).

Income Tax

($ millions)	Three Months Ended March 31, 2019	2018
Current Tax		
Canada	**4**	(58)
United States	**2**	4
Current Tax Expense (Recovery)	**6**	(54)
Deferred Tax Expense (Recovery)	**41**	(104)
Total Tax Expense (Recovery) From Continuing Operations	**47**	(158)

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 expense from continuing operations was recorded in the first quarter of 2019 compared with a current tax recovery in 2018 due to the carry back of losses in 2018 to recover tax paid in previous years.

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 capital gains and losses.

DISCONTINUED OPERATIONS

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. After-tax earnings from discontinued operations were $9 million and an after-tax gain on discontinuance of $251 million was recorded on the sale.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	Three Months Ended March 31, 2019	2018
Cash From (Used In)		
Operating Activities – Continuing Operations	**436**	(134)
Operating Activities – Discontinued Operations	**-**	11
Total Operating Activities	**436**	(123)
Investing Activities – Continuing Operations	**(314)**	(490)
Investing Activities – Discontinued Operations	**-**	451
Total Investing Activities	**(314)**	(39)
Net Cash Provided (Used) Before Financing Activities	**122**	(162)
Financing Activities	**(652)**	(59)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(7)**	16
Increase (Decrease) in Cash and Cash Equivalents	**(537)**	(205)

	March 31, 2019	December 31, 2018
Cash and Cash Equivalents	**244**	781
Committed and Undrawn Credit Facility	**4,500**	4,500

Cash From (Used In) Operating Activities

In the first three months of 2019, cash was generated by operating activities in comparison with cash used in operating activities in the first quarter of 2018. This was a result of higher Operating Margin, as discussed in the Financial Results section of this MD&A, a decrease in general and administrative costs, primarily due to $43 million of severance costs recognized in 2018, a decrease in finance costs, as discussed in the Corporate and Elimination section of this MD&A, an increase in current income tax expense, and changes in non-cash working capital, as discussed in the Financial Results section of this MD&A.

Excluding risk management assets and liabilities and the current portion of the contingent payment, our working capital was $549 million at March 31, 2019 compared with $450 million at December 31, 2018.

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 2019, cash used in investing activities was lower in 2019 compared with 2018 due to decreased capital investment.

Cash From (Used In) Financing Activities

In the first quarter of 2019, cash was used in financing activities primarily due to the repurchase of US$449 million of unsecured notes for cash of US$419 million.

Total debt as at March 31, 2019 was $8,383 million (December 31, 2018 - $9,164 million), with principal payments of US$0.5 billion due on October 15, 2019.

As at March 31, 2019, we were in compliance with all of the terms of our debt agreements.

Dividends

In the first quarter of 2019, we paid dividends of $0.05 per common share or $61 million (2018 – $0.05 per common share or $60 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 2019. 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, 2019:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**244**
Committed Credit Facility – Tranche A	**November 2022**	**3,300**
Committed Credit Facility – Tranche B	**November 2021**	**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, 2021 and $3.3 billion tranche maturing on November 20, 2022. As of March 31, 2019, no amounts were drawn on our committed credit facility.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in November 2019. As at March 31, 2019, 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, E&E Write-down, 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 twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at	**March 31, 2019**	December 31, 2018
Net Debt to Capitalization (percent)	**32**	32
Net Debt to Adjusted EBITDA [(1)]	**3.1x**	5.9x

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Over the long-term, Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. At different points within the economic cycle, we expect this ratio may periodically be above the target. 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. We also manage our Net Debt to Capitalization ratio to ensure compliance with the associated covenants as defined in our committed credit facility agreement.

Subsequent to March 31, 2019, we repurchased a further US$66 million of unsecured notes for cash of US$63 million.

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.

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, 2019, there were approximately 1,229 million common shares outstanding (2018 – 1,229 million common shares).

Refer to Note 21 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, 2019	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares [1]	**1,228,790**	**N/A**
Stock Options	**32,512**	**23,167**
Other Stock-Based Compensation Plans	**18,273**	**1,581**

(1) ConocoPhillips continued to hold 208 million common shares issued as partial consideration related to the Acquisition.

Contractual Obligations and Commitments

Cenovus has obligations for goods and services entered into in the normal course of business. Obligations are primarily related to transportation agreements, 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 March 31, 2019 interim Consolidated Financial Statements and December 31, 2018 Consolidated Financial Statements.

On January 1, 2019, the Company adopted IFRS 16, which resulted in the recognition of lease liabilities related to operating leases on the balance sheet. These liabilities were previously reported as a commitment. For a reconciliation of our commitments as at December 31, 2018 to our lease liabilities as at January 1, 2019, see Note 3 to the interim Consolidated Financial Statements.

As at March 31, 2019, total commitments were $24 billion, of which $23 billion are for various transportation and storage commitments. Transportation and storage commitments include future lease commitments relating to railcar and storage tank leases that have not yet commenced of US$261 million and $154 million, respectively. The railcar leases are expected to commence in 2019 with lease terms between five and 10 years and the storage tank leases are expected to commence in 2019 with lease terms of 10 years. In addition, transportation commitments include $13 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2018 – $14 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, 2019, there were outstanding letters of credit aggregating $359 million issued as security for performance under certain contracts (December 31, 2018 – $336 million).

Legal Proceedings

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

Contingent Payment

In connection with the Acquisition and related to oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at March 31, 2019, the estimated fair value of the contingent payment was $370 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 2018 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,					
	2019			2018		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil	**(12)**	**230**	**218**	463	(111)	352
Refining	**(7)**	**1**	**(6)**	5	(3)	2
Interest Rate	**1**	**7**	**8**	-	(25)	(25)
Foreign Exchange	**(1)**	**(2)**	**(3)**	1	-	1
(Gain) Loss on Risk Management	**(19)**	**236**	**217**	469	(139)	330
Income Tax Expense (Recovery)	**5**	**(62)**	**(57)**	(126)	37	(89)
(Gain) Loss on Risk Management, After Tax	**(14)**	**174**	**160**	343	(102)	241

In the first quarter of 2019, we incurred realized gains on crude oil risk management activities as our contract prices exceeded settlement prices. Unrealized losses were recorded on our crude oil financial instruments in the first quarter of 2019 primarily due to the realization of settled positions and changes in market prices.

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. Further to those areas discussed in the annual Consolidated Financial Statement for the year ended December 31, 2018 and the annual MD&A, determining the lease term under IFRS 16, requires critical judgments.

Management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not exercise a termination option on a lease. The assessment is reviewed if a significant event or a significant change in circumstances occurs which affects this assessment.

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, 2019.

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

Changes in Accounting Policies

Leases

Effective January 1, 2019, we adopted IFRS 16. We applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the consolidated balance sheet, consolidated statements of earnings, other comprehensive income, shareholders' equity and cash flows have not been restated.

On adoption, Management elected to use the following practical expedients permitted under the new standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value;
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease;
- Account for lease and non-lease components as a single lease component for lease liabilities related to storage tanks; and
- Use the Company's previous assessment under IAS 37, "*Provisions, Contingent Liabilities and Contingent Assets*" ("IAS 37") for onerous contracts instead of reassessing the ROU asset for impairment on January 1, 2019.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "*Leases*" ("IAS 17"). Under the principles of the new standard these leases have been measured at the present value of the remaining lease payments, discounted using our incremental borrowing rates at January 1, 2019. Incremental borrowing rates as at January 1, 2019 range from 4.0 percent to 5.7 percent. Leases with a remaining term of less than twelve months and low-value leases were excluded. The associated ROU assets were measured at the amount equal to the lease liability on January 1, 2019 less any amount previously recognized under IAS 37 for onerous contracts with no impact on retained earnings.

The impact of the adoption of IFRS 16 as at January 1, 2019 is as follows:

- Recorded lease liabilities of $1.5 billion, of which $128 million is the current portion;
- Recorded ROU assets of $893 million, equal to the lease liabilities less the previously recognized onerous contract provisions and a $16 million net investment in finance leases;
- Decreased the onerous contract provisions by $585 million, offsetting the ROU asset; and
- Recognized certain subleases as a net investment in finance leases ($16 million) that were classified as operating leases under IAS 17.

The adoption of the new standard had the following impact to our Q1 2019 financial results compared with what would have occurred had we not adopted the new accounting policy:

- Decrease in purchased product of $8 million;
- Decrease to transportation and blending costs of $16 million;
- Decrease to operating costs of $1 million;
- Decrease to general and administrative expenses of $18 million;
- Increase to DD&A expense of $34 million; and
- Increase in finance expenses of $19 million.

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 3 to the interim Consolidated Financial Statements.

Uncertain Tax Positions

Effective January 1, 2019, we adopted International Financial Reporting Interpretation Committee ("IFRIC") 23, *"Uncertainty over Income Tax Treatments"* using the modified approach. The interpretation provides clarity on how to account for a tax position when there is uncertainty over income tax treatments. In determining the likely resolution of the uncertain tax positions, a position may be considered separately or as a group. In addition, an assessment is required to determine the probability that the tax authority will accept the tax position taken in income tax filings. If the uncertain income tax treatment is unlikely to be accepted, the accounting tax position must reflect an appropriate level of uncertainty. An uncertain tax position may be reassessed if new information changes the original assessment. The adoption of IFRIC 23 did not have a material impact on the interim Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

There were no new or amended standards issued during the first quarter of 2019 that are applicable to Cenovus in future periods.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2019 that have materially affected, or are reasonably likely to materially affect ICFR.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

OUTLOOK

We expect the remainder of 2019 will see continued commodity price volatility and market access constraints for heavy oil exiting Alberta. Transportation challenges, such as the delay of Enbridge Inc.'s Line 3 Replacement Program, will continue to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects in North America to proceed as soon as possible. While our production levels have been impacted by the government mandated production curtailments, the resulting narrowing price differentials is anticipated to continue to have a positive impact on our cash flows. Curtailment restrictions are expected to decline in the remainder of 2019 as storage levels are projected to normalize and as increased crude-by-rail capacity help alleviate takeaway capacity constraints. Christina Lake phase G achieved first steam and is ready for production, which allows us flexibility on start-up. Timing of start-up of phase G will depend on production curtailments, crude-by-rail takeaway capacity ramping up, and the in-service date of Enbridge's Line 3 Replacement Program.

We will continue to look for ways to increase our margins through 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 anticipate taking delivery of rail cars beginning in the second quarter to support the plan to raise crude-by-rail shipments to approximately 100,000 barrels per day as pipeline project approvals continue to be stalled.

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 further help support our financial resilience.

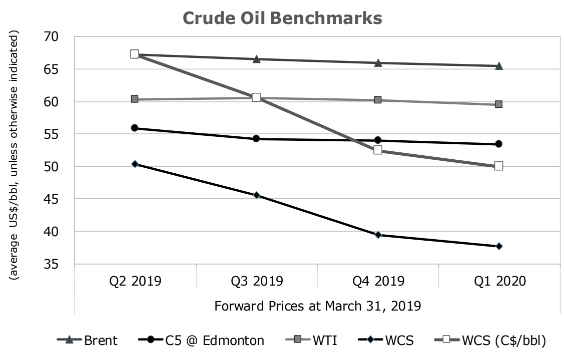
The following outlook commentary is focused on the next twelve months.

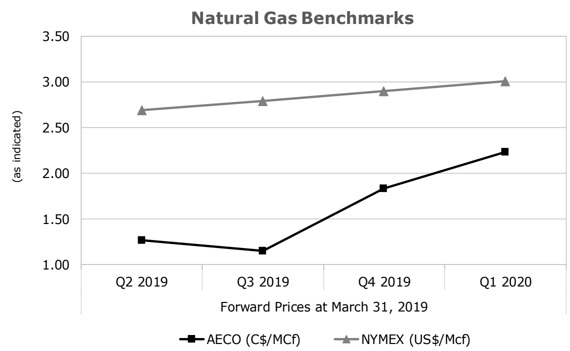
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices to remain constructive and largely tied to the degree to which the U.S. enforces export sanctions on Iranian crude oil, and the degree to which global demand growth continues;
- Overall, crude oil price volatility is expected to decrease as global inventories return to historical levels;
- Continuing OPEC cuts, enforcement of Iranian sanctions, and Venezuelan production declines will be supportive of the narrowing of global light-heavy crude oil price differentials;

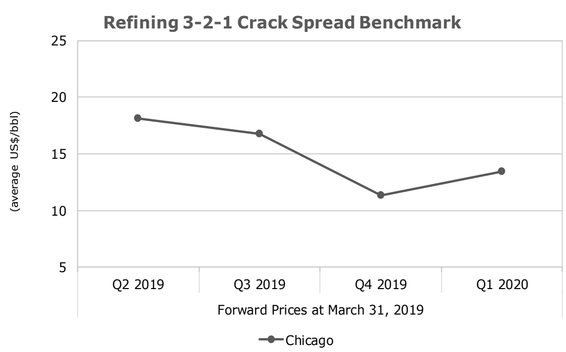
- We expect that the WTI-WCS differential will remain largely tied to the extent to which production curtailments in Alberta remain in place, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, the extent to which the turmoil in Venezuela continues and increasing crude-by-rail activity will reduce storage levels and support a narrower differential relative to recent highs;
- We anticipate that the pending International Maritime Organization regulations will cause light-heavy crude oil price differentials to widen, although the magnitude of the widening remains uncertain; and
- We expect refining crack spreads will likely continue to fluctuate, adjusting for seasonal trends, and will narrow once the Brent-WTI differential narrows.

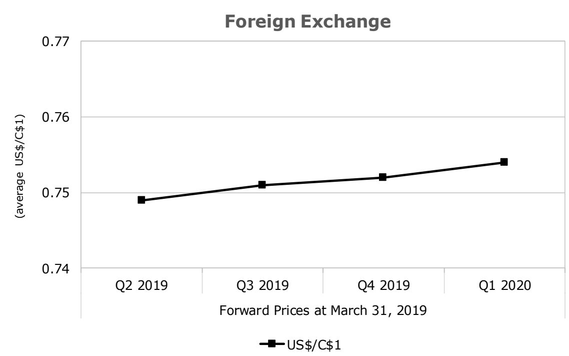




Natural gas prices are anticipated to remain challenged with North American supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain wide as increasing supply is anticipated to exceed the limits of existing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

We expect the Canadian dollar to continue to be tied to crude oil prices, the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise benchmark lending rates relative to each other, and emerging macro-economic factors. The Bank of Canada raised its benchmark lending rate in October 2018, but the rate has remained unchanged since, marking a notable shift for Canada towards an expansionary 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 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;
- 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 and entering into agreements with third parties to move additional rail volumes to alleviate a portion of near-term takeaway capacity constraints;
- 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;
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production well rates in response to pipeline capacity constraints, crude-by-rail export capacity, mandated production curtailments and crude oil price differentials; and

- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential.

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 2019

Deleveraging and Disciplined Capital Investment

In 2019, our focus will be on further deleveraging our balance sheet and maintaining capital discipline in an effort to position Cenovus to have the flexibility to balance increasing returns to shareholders with disciplined investment in potential high-return growth projects. Maintaining our financial resilience and flexibility while continuing to deliver safe and reliable operations remains a top priority.

As a result of our continued focus on capital discipline and in order to reflect the government mandated production limits as well as the impacts of IFRS 16, we have updated our 2019 guidance dated April 23, 2019. We anticipate capital investment to be between $1.2 billion and $1.4 billion, consistent with our guidance dated December 10, 2018. Our oil sands production is expected to range between 350 and 370 barrels per day for the remainder of 2019, depending on how long the mandated production curtailments remain in place, as well as the ramp up of our crude-by-rail program. We continue to plan to direct the majority of our 2019 capital budget towards sustaining oil sands production. We have flexibility on when we ramp-up production from Christina Lake phase G, and will consider whether mandated production curtailments have been lifted and if there is sustained improvement in market access and heavy oil benchmark prices. In response to the current commodity price environment and our continued focus on near-term debt reduction, we are taking a very disciplined approach in the Deep Basin, with the goal of reducing costs, improving efficiencies and maximizing value. With integration remaining an important part of our overall strategy, capital investment is also allocated for reliability work at the Refineries.

As at March 31, 2019, our net debt position was $8.1 billion. Through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $4.7 billion of liquidity as at March 31, 2019.

Over the long-term, we continue to target 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.

We remain committed to increasing shareholder value through cost leadership, capital discipline and safe and reliable operations. These commitments, in combination with our high-quality upstream assets and joint ownership in strong refining assets, are expected to strengthen our ability to generate free funds flow and continue to deleverage our balance sheet in 2019.

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. We anticipate taking delivery of rail cars starting in the second quarter under the agreements signed in late 2018. Delivery will continue through 2019 ramping up to 100,000 barrels per day.

Cost Leadership

Over the past four years, we have achieved significant improvements in our operating and sustaining capital costs. In 2019, we continue to look for ways to improve efficiencies across Cenovus to drive incremental capital, operating and general and administrative cost reductions. We expect to realize additional savings through 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 believe growth in cash flows and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target of less than 2.0 times.

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 in an effort to leverage our technology spend.

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2018 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 independent qualified reserves evaluators January 1, 2019 price forecasts. 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, 2018.

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 "aim", "anticipate", "believe", "can be", "capacity", "committed", "commitment", "could", "expect", "estimate", "focus", "forecast", "forward", "future", "guidance", "may", "on track", "outlook", "plan", "position", "potential", "priority", "projection", "pursue", "schedule", "strategy", "should", "target", "will", or similar expressions and includes suggestions of future outcomes, including statements about: strategy and related milestones; schedules and plans; focus on maximizing shareholder value through cost leadership; desire to realize the best margins for our products; plans to maintain and demonstrate financial discipline while balancing growth and shareholder return; continuing to advance our operational performance and upholding our trusted reputation; expected timing for oil sands expansion phases and associated expected production capacities; projections for 2019 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; future opportunities for oil and natural gas 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; all statements with respect to our 2019 guidance estimates; expected future production, including the timing, stability or growth thereof; the impact of the Government of Alberta's mandatory production curtailment; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that our capital investment and any cash dividends for 2019 will be funded from internally generated cash flows and cash balance on hand; expected reserves; capacities, including for projects, transportation and refining; all statements related to government royalty regimes applicable to Cenovus, which regimes are subject to change; 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 2019; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact; potential impacts of various risks, including those related to commodity prices and climate change; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof, and anticipated impact on the Consolidated Financial Statements; the availability and repayment of our credit facilities; potential asset sales; expected impacts of the contingent payment; 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 our 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 2019 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; 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 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; the Government of Alberta's mandatory production curtailment will narrow the differential between WTI and WCS crude oil prices thereby positively impacting cash flows for Cenovus; the ability of our refining capacity, dynamic storage, existing pipeline commitments, financial hedge transactions and plans to ramp up crude-by-rail loading capacity to partially mitigate a portion of our WCS crude oil volumes against wider differentials; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; 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 within the timelines we expect; forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS 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.

2019 guidance, as updated April 23, 2019, assumes: Brent prices of US$66.00/bbl, WTI prices of US$59.00/bbl; WCS of US$44.50/bbl; AECO natural gas prices of $1.55/Mcf; Chicago 3-2-1 crack spread of US$15.00/bbl; and an exchange rate of $0.75 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: our ability to realize the anticipated benefits of and synergies from the Acquisition; our ability 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; our ability 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; failure of the Government of Alberta's mandatory production curtailment to cause the differential between the WTI and the WCS crude oil prices to narrow or to narrow sufficiently to positively impact our cash flows; 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 regarding commodity prices, currency and interest rates; 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; our ability to maintain 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 judgments; 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 and our assumptions relating thereto; 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, shareholder proposals 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 our MD&A for the period ended December 31, 2018, 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		
WTS	West Texas Sour		

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, 2019 ($ millions)	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	2,427	220	2,647	(946)	-	(80)	(19)	1,602
Royalties	177	14	191	-	-	-	-	191
Transportation and Blending	1,147	19	1,166	(946)	-	-	-	220
Operating	274	93	367	-	-	(80)	(10)	277
Production and Mineral Taxes	-	-	-	-	-	-	-	-
Netback	829	94	923	-	-	-	(9)	914
(Gain) Loss on Risk Management	(12)	-	(12)	-	-	-	-	(12)
Operating Margin	841	94	935	-	-	-	(9)	926

	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
Three Months Ended March 31, 2018 ($ millions) [3]	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

(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.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

Oil Sands

	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements[3]
Three Months Ended March 31, 2019 ($ millions)	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	722	755	1,477	-	946	-	4	2,427
Royalties	61	116	177	-	-	-	-	177
Transportation and Blending	130	71	201	-	946	-	-	1,147
Operating	146	124	270	-	-	-	4	274
Netback	385	444	829	-	-	-	-	829
(Gain) Loss on Risk Management	(5)	(7)	(12)	-	-	-	-	(12)
Operating Margin	390	451	841	-	-	-	-	841

	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements[4]
Three Months Ended March 31, 2018 ($ millions) [3]	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	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

(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A
(4) Found in Note 1 of the interim Consolidated Financial Statements.

Deep Basin

Three Months Ended March 31, 2019 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[2]	Per Interim Consolidated Financial Statements[1] Total Deep Basin
Gross Sales	**205**	**15**	**220**
Royalties	**14**	**-**	**14**
Transportation and Blending	**19**	**-**	**19**
Operating	**87**	**6**	**93**
Production and Mineral Taxes	**-**	**-**	**-**
Netback	**85**	**9**	**94**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**85**	**9**	**94**

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, 2019	2018
Oil Sands		
Foster Creek	**154,369**	163,911
Christina Lake	**176,079**	202,212
Total Oil Sands Crude Oil	**330,448**	366,123
Natural Gas (MMcf per day)	**-**	4
Total Oil Sands (BOE per day)	**330,448**	366,865
Deep Basin		
Total Liquids	**28,003**	35,479
Natural Gas (MMcf per day)	**458**	549
Total Deep Basin (BOE per day)	**104,290**	127,056
Less: Internal Consumption [3] (MMcf per day)	**(320)**	(322)
Sales From Continuing Operations [3] (BOE per day)	**381,444**	440,254

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