MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2018

This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 12, 2019, should be read in conjunction with our December 31, 2018 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as of February 12, 2019, unless otherwise indicated. This MD&A 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 Audit Committee of the Cenovus Board of Directors (the "Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 12, 2019. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

This MD&A and the Consolidated Financial Statements and comparative information have been prepared in Canadian dollars, (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.

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 11 of our 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 December 31, 2018 we had an enterprise value of approximately $19 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 484,000 BOE per day in 2018. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 446,000 gross barrels per day of crude oil feedstock into an average of 470,000 gross barrels per day of refined products in 2018.

Our Strategy

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.

Our Strategic Focus Areas:

Oil sands

We are committed to maintaining and improving our industry-leading position as a low-cost oil sands operator and the largest in situ producer by leveraging our track record of strong operational performance while demonstrating technical leadership to improve reserves, production and earnings. We will also focus on advancing innovation to unlock future opportunities that maximize value from our vast resource base and improve our environmental footprint.

Conventional oil and natural gas

We will aim to employ disciplined investment in focused land positions across our conventional oil and natural gas portfolio to generate strong diversified returns, complementing our longer-term oil sands investments with short-cycle development opportunities.

Marketing, transportation & refining

We will strive to maximize the value from our oil and gas resources through increased participation along the value chain. Our integrated approach to transportation, storage, marketing, upgrading and refining helps optimize margins from each barrel of oil we produce.

People

We strive to maintain an engaging workplace where people can grow their skills and capabilities to adapt to an ever-changing environment while delivering results for the business. We are focused on upholding trust in the communities where we operate by living up to our values and commitments.

Our Operations

Oil Sands

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

Deep Basin

Our Deep Basin operations include liquids rich natural gas, condensate and other NGLs, and light and medium oil assets located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities (collectively, the "Deep Basin Assets"). The Deep Basin Assets were acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") in conjunction with their 50 percent interest in the FCCL Partnership ("FCCL") on May 17, 2017 (the "Acquisition"). The Deep Basin Assets provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. A portion of the natural gas we produce is used as fuel in our oil sands operations and provides an economic hedge for the natural gas required as a fuel source at our refining operations.

Refining and Marketing

Our operations include two refineries located in the U.S. in Illinois and Texas that are jointly owned with (50 percent interest) and operated by Phillips 66, an unrelated U.S. public company. In 2018, the gross crude oil capacity at the Wood River refinery and Borger refinery (the "Refineries") was approximately 314,000 barrels per day and 146,000 barrels per day, respectively. As a result of consistently strong operating performance, higher utilization rates and optimizations executed in 2018, both Refineries have been re-rated to reflect higher processing capacity, effective January 1, 2019. Crude capacity at the Wood River refinery was re-rated to 333,000 barrels per day, while capacity at the Borger refinery was re-rated to 149,000 barrels per day. This includes processing capability of up to 255,000 gross barrels per day of blended heavy crude oil. The refining operations allow us to capture the value from crude oil production through to refined products, such as diesel, gasoline and jet fuel, to partially mitigate volatility associated with regional North American light/heavy crude oil price differential fluctuations.

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

Operating Margin Net of Related Capital Investment

Year Ended December 31, 2018 ($ millions)	Oil Sands	Deep Basin	Refining and Marketing
Operating Margin	1,086	312	996
Capital Investment	887	211	208
Operating Margin Net of Related Capital Investment	199	101	788

YEAR IN REVIEW

In 2018, we delivered on the commitments we made to our shareholders. We demonstrated capital discipline and cost leadership, made significant progress in deleveraging our balance sheet, and strengthened our long-term market access position. Operational performance continued to be strong, with production from continuing operations averaging 483,458 BOE per day, a 32 percent increase from 2017. The Refineries also demonstrated excellent operational performance in 2018, with both Wood River and Borger operating above nameplate capacity in the second half of the year following major planned turnarounds in the first quarter.

Crude oil prices continued to be very volatile in 2018, with West Texas Intermediate ("WTI") reaching nearly US$80 per barrel in October and exiting the year more than US$30 per barrel lower. Overall, WTI prices averaged 27 percent higher than in 2017, while Western Canadian Select ("WCS") were negatively impacted by takeaway capacity constraints. The differential between WTI and WCS prices averaged US$26.31 per barrel, a 120 percent increase compared with 2017, reaching a record of US$52.00 per barrel in the fourth quarter, leaving the average WCS benchmark price relatively unchanged year over year. Flat WCS prices, increased condensate costs consistent with the rise in WTI benchmark prices, and significant realized risk management losses negatively impacted our financial results (operating margin) from our upstream assets. At the same time, the wide differentials between WTI and WCS as well as WTI and West Texas Sour ("WTS") crude oil prices provided a feedstock cost advantage at our Refineries increasing year over year financial results (operating margin) from that portion of our business.

Our net loss for the year of $2.7 billion reflects the write off of $2.1 billion of exploration and evaluation ("E&E") costs in the Deep Basin, a loss on the sale of the Cenovus Pipestone Partnership ("CPP"), and an onerous contract provision related to real estate of $629 million following the sublease of a significant portion of excess real estate. We also incurred severance costs related to workforce reductions.

In 2018, we:

- Repaid US$876 million of our unsecured notes, reducing net debt to $8.4 billion, driven by Free Funds Flow of $311 million and proceeds from asset divestitures of $1,050 million. In January 2019, we repurchased a further US$324 million of our unsecured notes at a discount;
- Strengthened our long-term market access position through three-year rail agreements to transport approximately 100,000 barrels per day of heavy crude oil from northern Alberta to various destinations on the U.S. Gulf Coast, providing a means of mitigating some of the price impact of pipeline congestion;
- Increased our committed capacity on the Keystone XL Pipeline project by 100,000 barrels per day;
- Reduced oil sands operating costs to $7.65 per barrel, a nine percent decrease from 2017;
- Earned an average companywide Netback from continuing operations, before realized hedging, of $18.51 per BOE, down 11 percent from 2017;
- Achieved upstream operating margin from continuing operations of $1,398 million compared with $2,394 million in 2017, due in part to realized risk management losses of $1,577 million largely as a result of hedging contracts established in 2017;
- Achieved nearly $1.0 billion of operating margin from Refining and Marketing due to strong crude utilization rates at both Refineries and the feedstock cost advantage associated with wider crude oil differentials;
- Re-evaluated our Deep Basin E&E projects in line with our current business plan. As a result, we wrote off previously capitalized E&E costs of $2.1 billion in the fourth quarter as an exploration expense;

- Recorded a net loss from continuing operations of $2,916 million compared with net earnings of $2,268 million in 2017;
- Invested $1,363 million of capital compared with $1,661 million in 2017, reflecting our continued focus on capital discipline, a smaller sustaining well and re-drill program than the prior year, and lower than expected capital investment to progress Christina Lake phase G;
- Achieved payout for royalty purposes at our Christina Lake project upon cumulative project revenues exceeding cumulative project allowable costs, resulting in the royalty calculation now being based on post-payout royalty rates, as discussed in the Oil Sands section of this MD&A; and
- Reached an agreement to sublease a portion of our Calgary office space that was in excess of our requirements.

On December 2, 2018, the Government of Alberta announced a temporary mandatory oil production curtailment for Alberta producers, starting in January 2019, to address the record-high differentials. While our production levels in 2019 will be impacted due to the curtailment, the expected improvement to oil prices is anticipated to have a positive impact on our cash flows.

OPERATING RESULTS

Upstream Production Volumes

	2018	**Percent Change**	2017	Percent Change	2016
Continuing Operations					
Liquids (barrels per day)					
Oil Sands					
Foster Creek	**161,979**	**30**	124,752	78	70,244
Christina Lake	**201,017**	**20**	167,727	111	79,449
	362,996	**24**	292,479	95	149,693
Deep Basin					
Crude Oil	**5,916**	**51**	3,922	-	-
NGLs	**26,538**	**57**	16,928	-	-
	32,454	**56**	20,850	-	-
Liquids Production (barrels per day)	**395,450**	**26**	313,329	109	149,693
Natural Gas (MMcf per day)					
Oil Sands	**1**	**(90)**	10	(41)	17
Deep Basin [(1)]	**527**	**67**	316	-	-
	528	**62**	326	1,818	17
Production From Continuing Operations (BOE per day)	**483,458**	**32**	367,635	141	152,527
Production From Discontinued Operations (Conventional) (BOE per day)	**294**	**(100)**	102,855	(14)	118,998
Total Production (BOE per day)	**483,752**	**3**	470,490	73	271,525

(1) Includes production used for internal consumption by the Oil Sands segment of 306 MMcf per day for the year ended December 31, 2018 (no internal usage of Deep Basin production in 2017 or 2016).

Our upstream operations performed very well as we successfully managed our production rates in response to pipeline capacity constraints and discounted heavy oil prices. Total production from continuing operations increased 32 percent compared with 2017, primarily due to the Acquisition contributing a full year of volumes in 2018. In addition, strong operational performance in the oil sands and increased production from the Deep Basin Assets contributed to higher volumes, partially offset by the divestiture of CPP on September 6, 2018.

Production for the year ended December 31, 2018 from our Conventional segment includes the results of our Suffield operations, which were sold on January 5, 2018. All references to our legacy Conventional segment are accounted for as a discontinued operation.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators (“IQREs”), at the end of 2018 we had total proved reserves of approximately 5.2 billion BOE, in line with 2017, while total proved plus probable reserves decreased two percent to approximately 7 billion BOE.

Additional information about our reserves is included in the Oil and Gas Reserves section of this MD&A.

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)	**2018**	2017	2016
Sales Price	**35.74**	36.86	27.37
Royalties	**3.43**	2.07	0.17
Transportation and Blending	**6.11**	5.43	6.51
Operating Expenses	**7.68**	8.46	8.94
Production and Mineral Taxes	**0.01**	0.01	-
Netback Excluding Realized Risk Management (1)	**18.51**	20.89	11.75
Realized Risk Management Gain (Loss)	**(9.90)**	(2.35)	3.22
Netback Including Realized Risk Management (1)	**8.61**	18.54	14.97

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

Our average Netback, excluding realized risk management gains and losses, decreased 11 percent in 2018 due to higher royalties and transportation and blending costs, as well as lower realized sales prices, partially offset by lower operating costs. The strengthening of the Canadian dollar relative to the U.S. dollar compared with 2017 had a negative impact on our sales price of approximately $0.05 per BOE.

Refining and Marketing

Both Refineries demonstrated strong operational performance in 2018 and benefited from higher realized crack spreads from improved product pricing and significantly wider WTI-WCS and WTI-WTS crude oil differentials, which created a feedstock cost advantage. Following major planned turnarounds that were substantially completed in the first quarter of 2018, crude utilization rates at both Refineries averaged above nameplate capacity in the second half of 2018.

	2018	**Percent Change**	2017	Percent Change	2016
Crude Oil Runs (1) (Mbbls/d)	**446**	**1**	442	-	444
Heavy Crude Oil (1)	**191**	**(5)**	202	(13)	233
Refined Product (1) (Mbbls/d)	**470**	**-**	470	-	471
Crude Utilization (1) (2) (percent)	**97**	**1**	96	(1)	97
Operating Margin ($ millions)	**996**	**67**	598	73	346

(1) Represents 100 percent of the Wood River and Borger refinery operations.
(2) Effective January 1, 2019, our refineries have nameplate capacity of 482,000 gross barrels per day.

Operating Margin from Refining and Marketing increased 67 percent in 2018 primarily due to wider crude oil price differentials, and a reduction in the cost of Renewable Identification Numbers ("RINs"), partially offset by increased operating costs due to the planned turnarounds at both Refineries in the first quarter of 2018.

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$/bbl, unless otherwise indicated)	**Q4 2018**	Q4 2017	**2018**	**Percent Change**	2017	2016
Brent						
Average	**68.08**	61.54	**71.53**	**30**	54.82	45.04
End of Period	**53.80**	66.87	**53.80**	**(20)**	66.87	56.82
WTI						
Average	**58.81**	55.40	**64.77**	**27**	50.95	43.32
End of Period	**45.41**	60.42	**45.41**	**(25)**	60.42	53.72
Average Differential Brent-WTI	**9.27**	6.14	**6.76**	**75**	3.87	1.72
WCS						
Average	**19.39**	43.14	**38.46**	**(1)**	38.97	29.48
Average (C$/bbl)	**25.60**	54.84	**49.81**	**(1)**	50.56	39.05
End of Period	**30.69**	34.93	**30.69**	**(12)**	34.93	38.81
Average Differential WTI-WCS	**39.42**	12.26	**26.31**	**120**	11.98	13.84
WTS						
Average	**52.38**	54.93	**57.24**	**15**	49.91	42.36
End of Period	**38.53**	60.47	**38.53**	**(36)**	60.47	52.27
Average Differential WTI-WTS	**6.43**	0.47	**7.53**	**624**	1.04	0.96
Condensate (C5 @ Edmonton)						
Average	**45.28**	57.97	**61.00**	**18**	51.57	42.47
Average (C$/bbl)	**59.74**	73.66	**79.02**	**18**	66.89	56.25
Average Differential WTI-Condensate (Premium)/Discount	**13.53**	(2.57)	**3.77**	**(708)**	(0.62)	0.85
Average Differential WCS-Condensate (Premium)/Discount	**(25.89)**	(14.83)	**(22.54)**	**79**	(12.60)	(12.99)
Mixed Sweet Blend ("MSW" @ Edmonton)						
Average	**32.51**	54.26	**53.65**	**11**	48.49	40.11
Average (C$/bbl)	**42.89**	68.95	**69.49**	**10**	62.89	53.13
End of Period	**44.19**	53.03	**44.19**	**(17)**	53.03	51.26
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**66.65**	74.36	**77.96**	**16**	66.95	56.24
Chicago Ultra-low Sulphur Diesel ("ULSD")	**84.25**	80.58	**86.75**	**26**	69.09	56.33
Refining Margin: Average 3-2-1 Crack Spreads (2)						
Chicago	**13.43**	21.09	**15.97**	**(5)**	16.77	13.07
Group 3	**14.57**	18.77	**16.74**	**1**	16.61	12.27
Average Natural Gas Prices						
AECO (C$/Mcf) (3)	**1.90**	1.96	**1.53**	**(37)**	2.43	2.09
NYMEX (US$/Mcf)	**3.64**	2.93	**3.09**	**(1)**	3.11	2.46
Basis Differential NYMEX-AECO (US$/Mcf)	**2.19**	1.40	**1.90**	**51**	1.26	0.89
Foreign Exchange Rate (US$ per C$1)						
Average	**0.758**	0.787	**0.772**	**-**	0.771	0.755
End of Period	**0.733**	0.797	**0.733**	**(8)**	0.797	0.745

(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

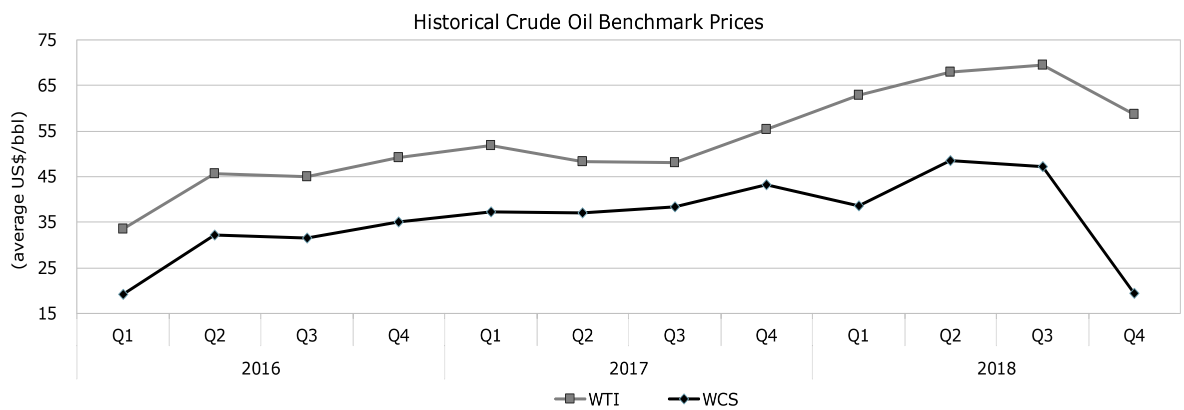
In 2018, the annual average Brent and WTI crude oil benchmark prices improved, while heavy oil differentials widened significantly in response to market access constraints and increasing heavy oil production in Alberta. Brent and WTI crude oil prices averaged 30 percent and 27 percent higher, respectively, compared with 2017, while WCS prices decreased one percent.

Continued uncertainty over Venezuelan supply and the possibility of the U.S. enforcing sanctions on Iran supported improved global crude oil benchmark pricing through the majority of 2018. Reduced inventory levels from compliance with production cuts outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries

("OPEC") and Russia have supported global oil prices. In June 2018, OPEC agreed to scale back over-compliance with production cuts by its members, which introduced the possibility of a modest increase in production and renewed concerns around oversupply. In addition, a reduced global demand outlook for 2019 and broader market weakness weighed on crude oil prices ahead of the December 2018 OPEC meeting, where OPEC once again agreed to cut production in an attempt to reduce inventory levels and support crude prices.

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 2018, the Brent-WTI differential widened significantly compared with 2017. WTI prices were limited by production from the Permian Basin exceeding available pipeline capacity out of west Texas, leading to increased volumes moving from Cushing, Oklahoma to the U.S. Gulf Coast on pipelines that were already nearing capacity. WTI prices were also negatively impacted in the second half of 2018 due to the start of seasonal refining maintenance in the Midwest and Midcontinent regions which reduced demand for crude oil.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential was significantly wider in 2018 compared with 2017. Increased production resulted in pipeline apportionments while the inability to transport additional volumes by rail in the short term and the lack of clarity surrounding future pipelines continued to put downward pressure on WCS benchmark prices. On December 2, 2018, the Government of Alberta announced temporary mandatory oil production curtailments for Alberta producers to address the record-high differentials, commencing January 2019. In response to the Government of Alberta's action, the differential between WTI and WCS has narrowed substantially thus far in 2019. The level of curtailment necessary is expected to drop over the course of 2019 as storage levels normalize, and as increased crude-by-rail capacity and the potential start-up of Enbridge Inc.'s Line 3 Replacement Project later this year help alleviate takeaway capacity constraints.



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 widened significantly in 2018, due primarily to pipeline congestion out of west Texas, as discussed above.

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.

Condensate benchmark prices averaged 18 percent higher in 2018, consistent with the rise in light oil prices over the same periods. The average WTI-condensate differential changed by US$4.39 per barrel, with condensate being sold at a discount to WTI in 2018 as compared with being sold at a premium in 2017. The condensate price discount relative to WTI in 2018 was due to high domestic inventories, in addition to increasing domestic supply combined with higher than anticipated imports.

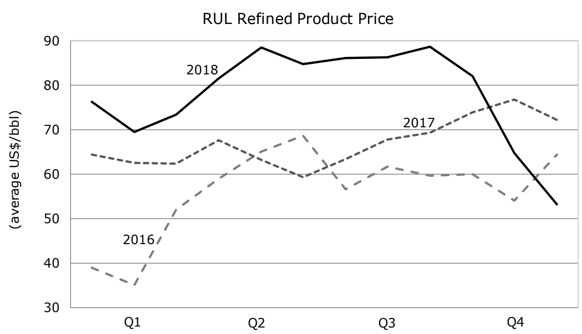
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price improved in 2018 compared with 2017, consistent with the general increase in average crude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

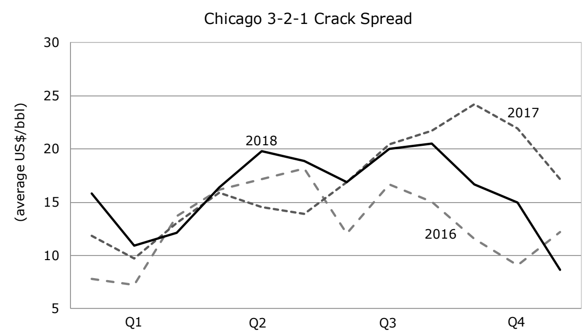
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 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 increased in 2018 primarily due to higher 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 2018, the Chicago 3-2-1 crack spread weakened five percent, while the Group 3 crack spread remained relatively unchanged from 2017.

Our realized crack spreads are affected by many other factors such as the variety of crude oil feedstock, refinery configuration and product output, the time lag between the purchase and delivery of crude oil feedstock, and the cost of feedstock which is valued on a first in, first out ("FIFO") accounting basis.





Natural Gas Benchmarks

Average AECO prices weakened during 2018 due to higher natural gas supply in Alberta and constrained export capabilities. Average NYMEX prices also decreased slightly compared with 2017 due to continued supply growth 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 2018, the Canadian dollar strengthened slightly relative to the U.S. dollar on average, compared with 2017, resulting in a negative impact of approximately $27 million on our revenues in 2018, excluding our Conventional segment. The Canadian dollar as at December 31, 2018 compared with December 31, 2017 was weaker relative to the U.S. dollar, resulting in $602 million of unrealized foreign exchange losses on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

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

($ millions, except per share amounts)	**2018**	**Percent Change**	2017	Percent Change	2016
Revenues	**20,844**	**22**	17,043	55	11,006
Operating Margin [1]					
From Continuing Operations	**2,394**	**(20)**	2,992	145	1,223
Total Operating Margin	**2,431**	**(30)**	3,483	97	1,767
Cash From Operating Activities					
From Continuing Operations	**2,118**	**(19)**	2,611	513	426
Total Cash From Operating Activities	**2,154**	**(30)**	3,059	255	861
Adjusted Funds Flow [2]					
From Continuing Operations	**1,637**	**(33)**	2,447	154	965
Total Adjusted Funds Flow	**1,674**	**(43)**	2,914	105	1,423
Operating Earnings (Loss) [2]					
From Continuing Operations	**(2,755)**	**(8,003)**	(34)	88	(291)
Per Share ($) [3]	**(2.24)**	**(7,367)**	(0.03)	91	(0.35)
Total Operating Earnings (Loss)	**(2,729)**	**(2,266)**	126	(133)	(377)
Per Share ($) [3]	**(2.22)**	**(2,118)**	0.11	(124)	(0.45)
Net Earnings (Loss)					
From Continuing Operations	**(2,916)**	**(229)**	2,268	(594)	(459)
Per Share ($) [3]	**(2.37)**	**(215)**	2.06	(475)	(0.55)
Total Net Earnings (Loss)	**(2,669)**	**(179)**	3,366	(718)	(545)
Per Share ($) [3]	**(2.17)**	**(171)**	3.05	(569)	(0.65)
Total Assets	**35,174**	**(14)**	40,933	62	25,258
Total Long-Term Financial Liabilities [4]	**8,602**	**(11)**	9,717	52	6,373
Capital Investment [5]					
From Continuing Operations	**1,363**	**(6)**	1,455	70	855
Total Capital Investment	**1,363**	**(18)**	1,661	62	1,026
Dividends					
Cash Dividends	**245**	**9**	225	36	166
Per Share ($)	**0.20**	**-**	0.20	-	0.20

(1) Additional subtotal found in Notes 1 and 11 of the 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 Long-Term Debt, Risk Management, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(5) Includes expenditures on property, plant and equipment ("PP&E"), E&E assets and assets held for sale.

Revenues

($ millions)	2018 vs. 2017	2017 vs. 2016
Revenues, Comparative Year	**17,043**	11,006
Increase (Decrease) due to:		
Oil Sands	**2,421**	4,212
Deep Basin	**318**	514
Refining and Marketing	**1,331**	1,413
Corporate and Eliminations	**(269)**	(102)
Revenues, End of Year	**20,844**	17,043

Upstream revenues increased over 2017 due to incremental sales volumes, primarily due to the Acquisition, partially offset by lower realized pricing and higher royalties.

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

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

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

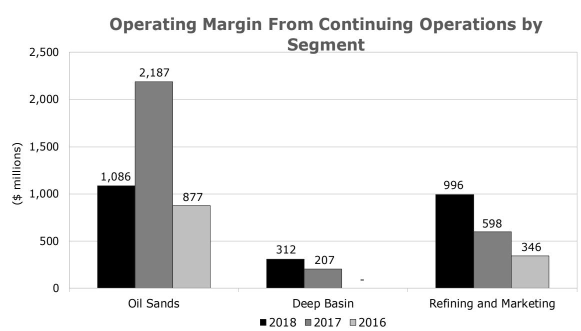
Operating Margin

Operating Margin is an additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending, operating expenses, production and mineral taxes plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin.

($ millions)	2018	2017	2016
Revenues	**21,568**	17,498	11,359
(Add) Deduct:			
Purchased Product	**9,261**	8,476	7,325
Transportation and Blending	**5,969**	3,760	1,721
Operating Expenses	**2,367**	1,956	1,243
Production and Mineral Taxes	**1**	1	-
Realized (Gain) Loss on Risk Management Activities	**1,576**	313	(153)
Operating Margin From Continuing Operations	**2,394**	2,992	1,223
Conventional (Discontinued Operations)	**37**	491	544
Total Operating Margin	**2,431**	3,483	1,767

Operating Margin from continuing operations decreased in 2018 compared with 2017 primarily due to:

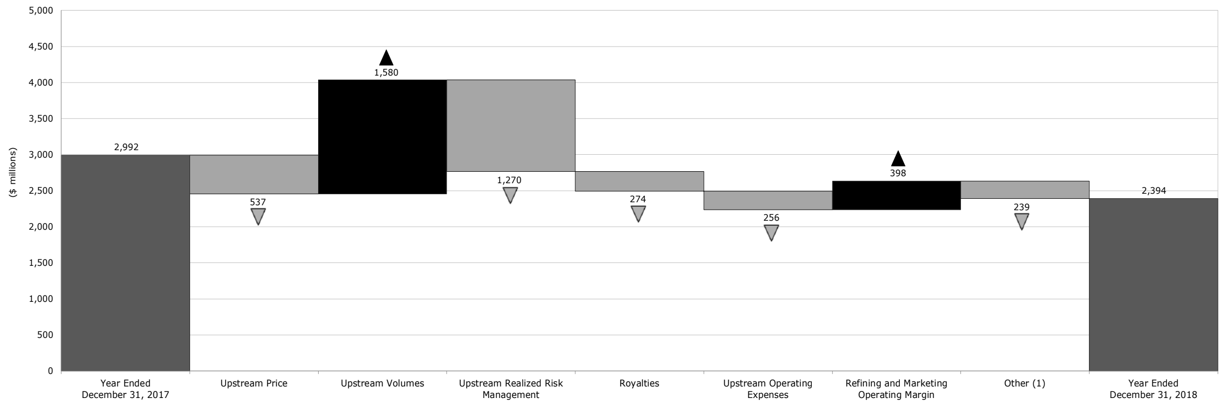
- A rise in transportation and blending expenses primarily due to the Acquisition resulting in increased condensate volumes required for blending our increased oil sands production, as well as higher condensate benchmark prices;
- Realized risk management losses of $1,576 million (2017 – losses of $313 million);
- A decrease in our average liquids sales price;
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), higher sales volumes, as well as the Christina Lake project reaching payout in the third quarter of 2018; and
- An increase in upstream operating expenses primarily due to the Acquisition.



These decreases in Operating Margin were partially offset by:

- A rise in our liquids and natural gas sales volumes as a result of the Acquisition; and
- Higher Operating Margin from our Refining and Marketing segment due to wider crude oil differentials.

Operating Margin From Continuing Operations Variance



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

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

Cash From Operating Activities and Adjusted Funds Flow

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

Total Cash From Operating Activities and Adjusted Funds Flow

($ millions)	**2018**	2017	2016
Cash From Operating Activities (1)	**2,154**	3,059	861
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(72)**	(107)	(91)
Net Change in Non-Cash Working Capital	**552**	252	(471)
Adjusted Funds Flow (1)	**1,674**	2,914	1,423

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

Cash From Operating Activities and Adjusted Funds Flow were lower compared with 2017 due to lower Operating Margin, as discussed above, a lower current tax recovery, and higher general and administrative costs primarily due to $60 million of severance costs, as well as increased rent costs. In 2017, we benefited from realized risk management gains of $146 million on foreign exchange contracts, partially offset by transaction costs of $56 million related to the Acquisition. These decreases were partially offset by changes in non-cash working capital in 2018 which was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable. In 2017, the change in non-cash working capital was primarily due to a decrease in accounts receivable and inventory, partially offset by higher income tax receivable and a decrease in accounts payable.

Operating Earnings (Loss)

Operating Earnings (Loss) is a non-GAAP measure used to provide a consistent measure of the comparability of our underlying financial performance between periods by removing non-operating items. Operating Earnings (Loss) is defined as Earnings (Loss) Before Income Tax excluding gain (loss) on discontinuance, revaluation gain, gain on bargain purchase, unrealized risk management gains (losses) on derivative instruments, unrealized foreign exchange gains (losses) on translation of U.S. dollar denominated notes issued from Canada, foreign exchange gains (losses) on settlement of intercompany transactions, gains (losses) on divestiture of assets, less income taxes on Operating Earnings (Loss) before tax, excluding the effect of changes in statutory income tax rates and the recognition of an increase in U.S. tax basis.

($ millions)	**2018**	2017	2016
Earnings (Loss) From Continuing Operations, Before Income Tax	**(3,926)**	2,216	(802)
Add (Deduct):			
Unrealized Risk Management (Gain) Loss (1)	**(1,249)**	729	554
Non-Operating Unrealized Foreign Exchange (Gain) Loss (2)	**593**	(651)	(196)
Revaluation (Gain)	**-**	(2,555)	-
(Gain) Loss on Divestiture of Assets	**795**	1	6
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**(3,787)**	(260)	(438)
Income Tax Expense (Recovery)	**(1,032)**	(226)	(147)
Operating Earnings (Loss) From Continuing Operations	**(2,755)**	(34)	(291)
Operating Earnings (Loss) From Discontinued Operations	**26**	160	(86)
Total Operating Earnings (Loss)	**(2,729)**	126	(377)

(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.

In 2018, Operating Earnings decreased primarily due to lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above, exploration expense of $2,123 million compared with $888 million in 2017, a non-cash provision of $629 million for onerous contracts related to office space, increased depreciation, depletion and amortization ("DD&A"), and an unrealized foreign exchange loss of $47 million on operating items compared with gains of $192 million in 2017.

Net Earnings (Loss)

($ millions)	**2018 vs. 2017**	2017 vs. 2016
Net Earnings (Loss) From Continuing Operations, Comparative Year	**2,268**	(459)
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**(598)**	1,769
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**1,978**	(175)
Unrealized Foreign Exchange Gain (Loss)	**(1,506)**	668
Revaluation (Gain)	**(2,555)**	2,555
Re-measurement of Contingent Payment	**(188)**	138
Gain (Loss) on Divestiture of Assets	**(794)**	5
Expenses (1)	**(951)**	(149)
DD&A	**(293)**	(907)
Exploration Expense	**(1,235)**	(886)
Income Tax Recovery (Expense)	**958**	(291)
Net Earnings (Loss) From Continuing Operations, End of Year	**(2,916)**	2,268

(1) 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.

In 2018, we incurred a net loss of $2,916 million from continuing operations, a significant decrease from 2017, due to:

- Lower Operating Earnings, as discussed above;
- An after-tax revaluation gain of $1.9 billion on our pre-existing interest in FCCL recognized in 2017;
- Non-operating foreign exchange losses of $593 million compared with gains of $651 million in 2017; and
- A before-tax loss of $797 million ($557 million after-tax) on the divestiture of CPP.

These decreases to our Net Earnings (Loss) from continuing operations in 2018 were partially offset by unrealized risk management gains of $1,249 million compared with losses of $729 million in 2017, and an income tax recovery of $1,010 million compared with a recovery of $52 million in 2017.

Net Earnings from discontinued operations for the year ended December 31, 2018 was $247 million (2017 – $1,098 million). Our 2018 results include an after-tax gain of $220 million on the divestiture of the Suffield assets in the first quarter of 2018. Our 2017 results include an after-tax gain of $938 million on the divestiture of the Conventional segment assets.

Total Capital Investment

($ millions)	**2018**	2017	2016
Oil Sands	**887**	973	604
Deep Basin	**211**	225	-
Refining and Marketing	**208**	180	220
Corporate and Eliminations	**57**	77	31
Capital Investment - Continuing Operations	**1,363**	1,455	855
Conventional (Discontinued Operations)	**-**	206	171
Total Capital Investment (1)	**1,363**	1,661	1,026

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

Capital investment in continuing operations decreased compared with 2017, reflecting our continued focus on capital discipline, a smaller sustaining well and re-drill program than the prior year, and lower than expected capital investment to progress Christina Lake phase G, partially offset by the 2017 results not reflecting a full year of operations following the Acquisition on May 17, 2017.

In 2018, Oil Sands capital investment focused on sustaining capital related to existing production; stratigraphic test wells to determine pad placement for sustaining wells; and the Christina Lake phase G expansion. The majority of our Deep Basin capital program was carried out in the first three months of 2018 and focused on all three operating areas, including the drilling of 15 net horizontal production wells targeting liquids rich natural gas, as well as capital invested in completions, facilities and infrastructure to support production.

Refining and Marketing capital investment increased in 2018 due to increased capital maintenance and reliability work compared with the same periods in 2017.

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

Capital Investment Decisions

We continue to focus on deleveraging our balance sheet. 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.

Deleveraging is a priority above growth and shareholder returns until we get to $7 billion of net debt. 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.

($ millions)	**2018**	2017	2016
Adjusted Funds Flow (1)	**1,674**	2,914	1,423
Total Capital Investment (1)	**1,363**	1,661	1,026
Free Funds Flow (1) (2)	**311**	1,253	397
Cash Dividends	**245**	225	166
	66	1,028	231

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

We expect our capital investment and cash dividends for 2019 to be funded from our internally generated cash flows and our cash balance on hand.

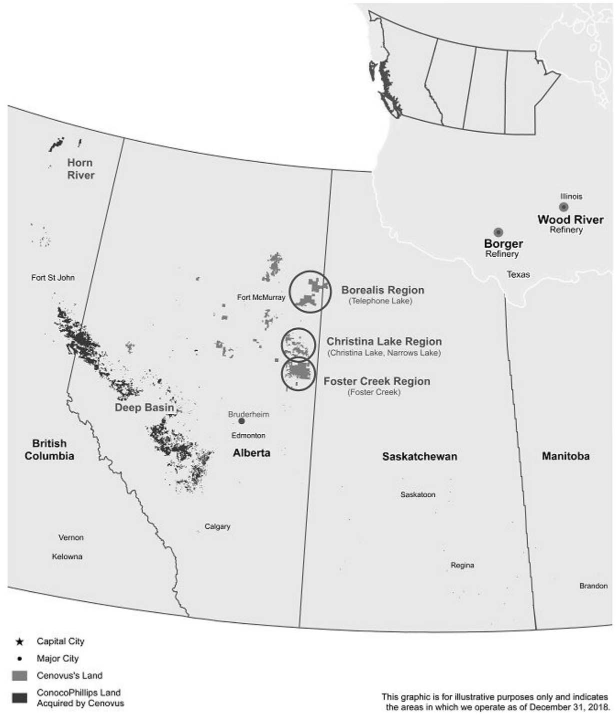
REPORTABLE SEGMENTS

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

Deep Basin, which includes approximately 2.8 million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and natural gas liquids. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. These assets were acquired on May 17, 2017.

Refining and Marketing, which is responsible for transporting, selling and refining crude oil into petroleum and chemical products. Cenovus jointly owns two refineries in the U.S. with the operator Phillips 66, an unrelated U.S. public company. In addition, Cenovus owns and operates a crude-by-rail terminal in Alberta. This segment coordinates Cenovus's marketing and transportation initiatives to optimize product mix, delivery points, transportation commitments and customer diversification.



Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, 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.

In 2017, Cenovus announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and conventional crude oil, NGLs and natural gas assets in the Suffield and Palliser areas in southern Alberta. As such, the associated results of operations have been reported as discontinued operations. 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

($ millions)	**2018**	2017	2016
Oil Sands [1]	**9,553**	7,132	2,920
Deep Basin [1]	**832**	514	-
Refining and Marketing	**11,183**	9,852	8,439
Corporate and Eliminations	**(724)**	(455)	(353)
	20,844	17,043	11,006

(1) *Our 2017 results include 229 days of FCCL operations at 100 percent and 229 days of operations from the Deep Basin Assets. See the Oil Sands and Deep Basin sections of this MD&A for more details.*

OIL SANDS

In northeastern Alberta, we own 100 percent of the Foster Creek, Christina Lake and Narrows Lake oil sands projects following the completion of the Acquisition. In addition, we have several emerging projects in the early stages of development. The Oil Sands segment includes the Athabasca natural gas property, from which the natural gas production is used as fuel at the adjacent Foster Creek operations.

In 2018, we:

- Increased total production by 24 percent over 2017 primarily due to the Acquisition;
- Earned crude oil netbacks of $19.70 per barrel, excluding realized risk management activities, a 20 percent decrease compared with 2017;
- Reduced oil sands operating costs to $7.65 per barrel, a nine percent decrease from 2017;
- Invested $198 million of growth capital to progress Christina Lake phase G, which is expected to be completed ahead of schedule and approximately 25 percent below the anticipated capital required to achieve the planned scope of work;
- Achieved project payout for royalty purposes at Christina Lake upon cumulative project revenues exceeding cumulative project allowable costs; and
- Generated Operating Margin net of capital investment of $202 million, an 84 percent decrease compared with 2017 as higher sales volumes were more than offset by increased transportation and blending costs, and realized risk management losses of $1,551 million compared with losses of $307 million in 2017.

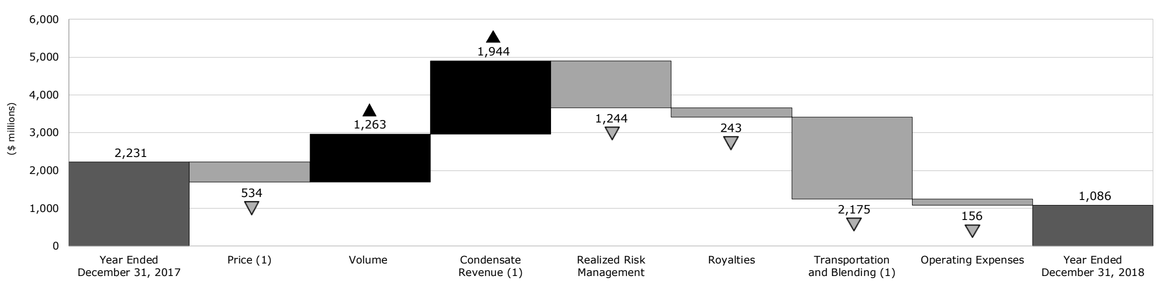
Oil Sands – Crude Oil

Financial Results [1]

($ millions)	2018	2017	2016
Gross Sales	**10,013**	7,340	2,911
Less: Royalties	**473**	230	9
Revenues	**9,540**	7,110	2,902
Expenses			
Transportation and Blending	**5,879**	3,704	1,720
Operating	**1,024**	868	486
(Gain) Loss on Risk Management	**1,551**	307	(179)
Operating Margin	**1,086**	2,231	875
Capital Investment	**886**	969	601
Operating Margin Net of Related Capital Investment	**200**	1,262	274

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

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 2018, our average realized crude oil sales price decreased to $37.51 per barrel (2017 – $41.49 per barrel). Light oil and condensate benchmark prices increased significantly in 2018, while at the same time, light-heavy crude oil price differentials increased, leaving heavy crude oil benchmark prices relatively unchanged year over year.

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 falling crude oil price environment, we expect to see a negative impact on our bitumen sales price as we are using condensate purchased at a higher price earlier in the year.

With WCS benchmark prices remaining flat in 2018 and the higher cost of condensate used in blending, our realized crude oil sales price was negatively impacted. The decrease in our crude oil price also reflects the wider WCS-Christina Dilbit Blend ("CDB") differential, which increased to a discount of US$3.17 per barrel (2017 – discount of US$1.67 per barrel).

Production Volumes

(barrels per day)	**2018**	**Percent Change**	2017	Percent Change	2016
Foster Creek	**161,979**	**30**	124,752	78	70,244
Christina Lake	**201,017**	**20**	167,727	111	79,449
	362,996	**24**	292,479	95	149,693

Oil Sands production averaged 362,996 barrels per day in 2018, a 24 percent increase primarily due to the Acquisition contributing a full year of volumes in 2018 compared with incremental volumes for 229 days in 2017.

In response to limited takeaway capacity and discounted heavy oil pricing, we made the decision to operate our Christina Lake and Foster Creek facilities at reduced production levels in the first quarter of 2018, and again starting in mid-September, leaving crude oil barrels in our reservoir to produce at a later date. 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 as pipeline capacity improves and crude oil differentials narrow. Stored volumes from the first quarter of 2018 were recovered in the second quarter as we ramped up production rates in response to narrowing crude oil differentials. Voluntary production curtailments from mid-September onward lowered our annualized 2018 production by approximately 13,000 barrels per day. The impact of curtailed production was mostly offset by improved operational performance at both oil sands facilities during the second and third quarters of 2018.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with a wider WCS-Condensate differential in 2018, the proportion of the cost of condensate recovered decreased. The total amount of condensate used increased as a result of higher production volumes.

Royalties

Royalty calculations for our oil sands projects are based on government prescribed pre- and post-payout royalty rates which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

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.

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 is a post-payout project.

During the third quarter of 2018, our Christina Lake property achieved project payout. Project payout is achieved when the cumulative project revenue exceeds the cumulative project allowable costs. The Christina Lake effective royalty rate increased to an average of 4.8 percent in 2018 from an average of 2.5 percent in 2017.

Effective Royalty Rates

(percent)	**2018**	2017	2016
Foster Creek	**18.0**	11.4	-
Christina Lake	**4.8**	2.5	1.6

Royalties increased $243 million in 2018 compared with 2017. Royalties at both Foster Creek and Christina Lake increased primarily due to a higher average WTI benchmark price (which determines the royalty rate), and higher volumes. In addition, Christina Lake achieving project payout in August 2018 increased royalty expenses during the third quarter, which was partially offset during the fourth quarter as higher crude oil differentials negatively impacted project revenues.

Expenses

Transportation and Blending

Transportation and blending costs increased $2,175 million compared with 2017 primarily due to the Acquisition. Blending costs increased primarily due to a rise in condensate volumes required for our increased production, as well as higher condensate prices, driven by higher light oil benchmark prices. Our condensate costs were higher than the average Edmonton benchmark price, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Per-unit Transportation Expenses

At Foster Creek, transportation costs decreased $0.39 per barrel due to a higher proportion of Canadian sales resulting in lower costs associated with pipeline tariffs. Christina Lake transportation costs increased $0.73 per barrel as a result of increased U.S. sales relative to 2017.

Operating

Primary drivers of our operating expenses in 2018 were workforce costs, fuel, chemical costs, repairs and maintenance and workovers. Total operating expenses increased $156 million primarily due to the Acquisition, increased chemical prices and increased natural gas consumption as a result of higher steam production in 2018, partially offset by a decrease in natural gas prices, lower workforce costs, and fewer workovers.

Per-unit Operating Expenses

($/bbl)	**2018**	**Percent Change**	2017	Percent Change	2016
Foster Creek					
Fuel	**2.13**	**(13)**	2.44	(1)	2.46
Non-fuel	**6.84**	**(15)**	8.02	(1)	8.09
Total	**8.97**	**(14)**	10.46	(1)	10.55
Christina Lake					
Fuel	**1.87**	**(9)**	2.06	(1)	2.08
Non-fuel	**4.73**	**(1)**	4.78	(11)	5.40
Total	**6.60**	**(4)**	6.84	(9)	7.48
Total	**7.65**	**(9)**	8.40	(6)	8.91

At both Foster Creek and Christina Lake, per-barrel fuel costs decreased in 2018 primarily due to lower natural gas prices. Foster Creek per-barrel non-fuel operating expenses decreased primarily due to higher sales volumes, a reduction in workforce costs, fewer workovers and lower repairs and maintenance costs, partially offset by higher chemical costs. At Christina Lake, per-barrel non-fuel operating expenses decreased due to higher sales volumes and lower workforce costs, partially offset by increased chemical costs.

Netbacks [1]

	Foster Creek			**Christina Lake**		
($/bbl)	**2018**	2017	2016	**2018**	2017	2016
Sales Price	**42.63**	43.75	30.32	**33.42**	39.78	25.30
Royalties	**6.25**	4.00	(0.01)	**1.37**	0.87	0.33
Transportation and Blending	**8.34**	8.73	8.84	**5.25**	4.52	4.68
Operating Expenses	**8.97**	10.46	10.55	**6.60**	6.84	7.48
Netback Excluding Realized Risk Management	**19.07**	20.56	10.94	**20.20**	27.55	12.81
Realized Risk Management Gain (Loss)	**(11.49)**	(2.95)	3.51	**(11.66)**	(2.99)	3.08
Netback Including Realized Risk Management	**7.58**	17.61	14.45	**8.54**	24.56	15.89

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

Risk Management

Risk management positions in 2018 resulted in realized losses of $1,551 million (2017 – realized losses of $307 million), consistent with average benchmark prices exceeding our contract prices. In 2017 we entered into hedging contracts with the intent to provide downside protection and support financial resilience following the Acquisition.

Oil Sands – Capital Investment

($ millions)	**2018**	2017	2016
Foster Creek	**379**	455	263
Christina Lake	**445**	426	282
	824	881	545
Other (1)	**63**	92	59
Capital Investment (2)	**887**	973	604

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

Oil Sands capital investment decreased $86 million in 2018 primarily due to a smaller sustaining well and re-drill program, as well as decreased spending on the Christina Lake phase G expansion compared with 2017. At Foster Creek, capital investment focused on sustaining capital related to existing production and stratigraphic test wells. Christina Lake capital investment focused on sustaining capital related to existing production, stratigraphic test wells and the phase G expansion.

Drilling Activity

	Gross Stratigraphic Test Wells			**Gross Production Wells (1)**		
	2018	2017	2016	**2018**	2017	2016
Foster Creek	**43**	96	95	**14**	41	18
Christina Lake	**63**	108	104	**38**	25	35
	106	204	199	**52**	66	53
Other	**23**	16	6	**3**	-	1
	129	220	205	**55**	66	54

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

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

Future Capital Investment

Foster Creek is currently producing from phases A through G. Capital investment for 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 and completing construction of the phase G expansion. Field construction of phase G, which has an initial design capacity of 50,000 barrels per day, is progressing ahead of schedule and is expected to be completed in the second quarter of 2019. We have flexibility on when we start production from Christina Lake phase G and will take into consideration whether mandated production curtailments have been lifted and 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.

Our Technology and other capital investment, forecast to be between $55 million and $65 million in 2019, 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.

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 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.

In 2018, Oil Sands DD&A increased by $209 million compared with 2017 as a result of increased production volumes. The average depletion rate for the year ended December 31, 2018 was approximately $10.60 per barrel (2017 – $11.50 per barrel).

Future development costs declined due to an increase in well pair lengths at Christina Lake, resulting in a reduction in the number of pads and well pairs required, as well as cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs. This decline was partially offset by an increase in the future development costs at Foster Creek as a result of a development area expansion.

Exploration Expense

Exploration expense of $6 million was recorded for the year ended December 31, 2018. In 2017, we expensed $888 million primarily related to E&E assets in the Greater Borealis area that were deemed not to be technically feasible or commercially viable. Management's decision was based on a comprehensive review of spending to date, decisions to limit spending on these assets in recent years and the current business plan spending on the assets going forward.

DEEP BASIN

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

In 2018, we:
- Produced a total of 120,258 BOE per day;
- Invested capital of $211 million, primarily in the first three months of the year, related to drilling 15 net horizontal production wells and completing 21 net wells, as well as capital related to facilities and infrastructure to support production;
- Earned a netback of $7.09 per BOE, excluding realized risk management activities;
- Generated Operating Margin of $312 million; and
- Closed the divestiture of CPP on September 6, 2018 for cash proceeds of $625 million, before closing adjustments.

Financial Results

($ millions)	2018	May 17 - December 31, 2017
Gross Sales	**904**	555
Less: Royalties	**72**	41
Revenues	**832**	514
Expenses		
Transportation and Blending	**90**	56
Operating	**403**	250
Production and Mineral Taxes	**1**	1
(Gain) Loss on Risk Management	**26**	-
Operating Margin	**312**	207
Capital Investment	**211**	225
Operating Margin Net of Related Capital Investment	**101**	(18)

Revenues

Price

	2018	May 17 - December 31, 2017
Light and Medium Oil ($/bbl)	**66.71**	60.01
NGLs ($/bbl)	**38.56**	33.05
Natural Gas ($/mcf)	**1.72**	2.03
Total Oil Equivalent ($/BOE)	**19.31**	19.52

For the year ended December 31, 2018, revenues include $57 million of processing fee revenue related to our interests in natural gas processing facilities (2017 – $31 million). We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	2018	2017
Liquids		
Crude Oil (barrels per day)	**5,916**	3,922
NGLs (barrels per day)	**26,538**	16,928
	32,454	20,850
Natural Gas (MMcf per day)	**527**	316
Total Production (BOE/d)	**120,258**	73,492
Natural Gas Production (percentage of total)	**73**	72
Liquids Production (percentage of total)	**27**	28

In 2018, production from the Deep Basin Assets was 120,258 BOE per day, a three percent increase in production from the closing of the Acquisition on May 17, 2017 to December 31, 2017, which averaged 117,138 BOE per day. The increase in production was primarily due to strong performance from the drilling program, partially offset by the divestiture of CPP on September 6, 2018. Production from CPP was approximately 8,800 BOE per day prior to the divestiture.

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 2018, our effective royalty rate was 12.8 percent for liquids and 3.6 percent for natural gas (2017 – 12.1 percent for liquids and 4.4 percent for natural gas).

Expenses

Transportation

Transportation costs averaged $1.97 per BOE in 2018 compared with $2.08 per BOE in 2017. 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, third-party processing fee expenses, and property tax and lease costs. Total operating expenses increased $153 million, reflecting a full year of operations in 2018 compared with 229 days in 2017, increased processing fees and higher electricity rates, partially offset by a reduction in repairs and maintenance activities, and lower workforce costs.

Netbacks

($/BOE)	**2018**	May 17 - December 31, 2017
Sales Price	**19.31**	19.52
Royalties	**1.64**	1.54
Transportation and Blending	**1.97**	2.08
Operating Expenses	**8.58**	8.56
Production and Mineral Taxes	**0.03**	0.02
Netback Excluding Realized Risk Management	**7.09**	7.32
Realized Risk Management Gain (Loss)	**(0.59)**	-
Netback Including Realized Risk Management	**6.50**	7.32

Risk Management

Risk management activities in 2018 resulted in realized losses of $26 million (2017 – $nil).

Deep Basin – Capital Investment

In 2018, capital investment was focused primarily on drilling high liquids yielding wells and de-risking resource potential. We completed the majority of our 2018 drilling program in the first three months of the year, with development focusing on all three operating areas including the drilling of 15 net horizontal wells, completing 21 net wells and bringing 25 net wells on production. Additional capital expenditures were allocated to facilities and infrastructure to support production in our core development areas.

($ millions)	**2018**	May 17 - December 31, 2017
Drilling and Completions	**111**	152
Facilities	**56**	32
Other	**44**	41
Capital Investment (1)	**211**	225

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

Drilling Activity

The following table summarizes Cenovus's net well activity:

	2018			May 17 - December 31, 2017		
	Drilled (1)	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Elmworth-Wapiti	**4**	**6**	**9**	9	5	-
Kaybob-Edson	**8**	**11**	**9**	7	5	6
Clearwater	**3**	**4**	**7**	12	10	8
Total	**15**	**21**	**25**	28	20	14

(1) Includes 13 operated net horizontal wells and two non-operated net horizontal wells for the year ended December 31, 2018.

Future Capital Investment

In the fourth quarter of 2018, Management completed a comprehensive review of the Deep Basin development plan considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. As a result, we have reduced capital investment and drilling plans in 2019 compared with 2018, with total Deep Basin capital investment forecast to be between $50 million and $75 million.

DD&A

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $10.55 per BOE for the year ended December 31, 2018 (2017 – $10.25 per BOE).

Deep Basin DD&A was $412 million in 2018 (2017 – $331 million). Earlier in 2018 and 2017, impairment losses of $100 million and $56 million, respectively, were recorded due to a decline in forward prices and a slowing of the development plan. The impairment was recorded as additional DD&A. In the fourth quarter of 2018, we reversed $132 million of the impairment losses, net of DD&A that would have been recorded had no impairment been recorded. The reversal was due to an increase of the cash-generating unit's ("CGUs") recoverable amount due to improved recovery, extensions and well performance and changes to the development plan.

Exploration Expense

In the fourth quarter of 2018, Management completed a comprehensive review of the Deep Basin development plan considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. Based on the revised development plan, it was determined that the carrying value of certain Deep Basin E&E assets were not fully recoverable resulting in previously capitalized E&E costs of $2.1 billion being written off as exploration expense within the Deep Basin segment. Management is committed to developing this significant resource; however, at a much slower pace of development. In 2017, exploration expense was $nil.

Assets and Liabilities Held for Sale

In the fourth quarter of 2017, we announced our intention to market for sale a package of non-core Deep Basin assets in the East Clearwater area and a portion of the West Clearwater assets. As a result, these assets were classified as assets held for sale and were recorded at the lesser of their carrying amount and fair value less costs to sell.

In December 2018, Management decided to discontinue this sales process until market conditions improve. As a result of this decision, as at December 31, 2018, the assets and associated decommissioning liabilities were reclassified from held for sale to PP&E, E&E and decommissioning liabilities, at their carrying amounts. Depletion, calculated on a per-unit of production basis, was recorded in the fourth quarter.

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. and operated by our partner, Phillips 66. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta.

In 2018, we:

- Completed major planned turnarounds at both Wood River and Borger refineries in the first quarter;
- Demonstrated new crude processing rates that will increase the nameplate capacities to a combined 482,000 gross barrels per day, effective January 1, 2019;
- Benefited from higher realized crack spreads due to improved product pricing and significantly wider WTI-WCS and WTI-WTS crude oil differentials compared with 2017, which created a feedstock cost advantage at both Refineries;
- Increased rail volumes loaded at the Bruderheim Energy Terminal, averaging 73,719 barrels per day in December, compared with an average of 18,997 barrels per day loaded in the first half of 2018;
- Executed rail agreements for capacity to move additional heavy crude oil from northern Alberta; and
- Generated Operating Margin of $996 million compared with $598 million in 2017.

Refinery Operations (1)

	2018	2017	2016
Crude Oil Capacity (Mbbls/d) (2)	**460**	460	460
Crude Oil Runs (Mbbls/d)	**446**	442	444
Heavy Crude Oil	**191**	202	233
Light/Medium	**255**	240	211
Refined Products (Mbbls/d)	**470**	470	471
Gasoline	**233**	238	236
Distillate	**156**	149	146
Other	**81**	83	89
Crude Utilization (percent)	**97**	96	97

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.
(2) Effective January 1, 2019, our refineries have nameplate capacity of 482,000 gross barrels per day.

On a 100 percent basis, the Refineries had total processing capacity in 2018 of approximately 460,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil and 45,000 gross barrels per day of NGLs. As a result of consistently strong operating performance, higher utilization rates and optimizations executed in 2018, both Refineries have been re-rated to reflect higher processing capacity, effective January 1, 2019. Total processing capacity as at January 1, 2019 is approximately 482,000 gross barrels per day of crude oil. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI, and the discount of 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 increased slightly, while refined product output was unchanged compared with 2017 as strong operational performance was partially offset by major planned turnarounds and maintenance at both Refineries in the first quarter of 2018. In 2018, lower heavy crude oil volumes were processed due to the optimization of the total crude input slate, which resulted in increased volumes of WTS being processed at the Borger refinery, in order to take advantage of the wider WTI-WTS crude oil differential.

Financial Results

($ millions)	2018	2017	2016
Revenues	**11,183**	9,852	8,439
Purchased Product	**9,261**	8,476	7,325
Gross Margin	**1,922**	1,376	1,114
Expenses			
Operating	**927**	772	742
(Gain) Loss on Risk Management	**(1)**	6	26
Operating Margin	**996**	598	346
Capital Investment	**208**	180	220
Operating Margin Net of Related Capital Investment	**788**	418	126

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 2018, Refining and Marketing gross margin increased primarily due to higher realized crack spreads from improved product pricing and significantly wider WTI-WCS and WTI-WTS crude oil differentials, which created a feedstock cost advantage. As at December 31, 2018, we recorded a $47 million write-down of our refined product inventory due to a decline in prices. The Canadian dollar strengthened relative to the U.S. dollar compared with 2017, which had a negative impact on our gross margin of approximately $10 million.

For the year ended December 31, 2018, the cost of RINs was $131 million compared with $296 million in 2017. The cost of RINs declined 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 2018 were maintenance, labour, and utilities. Operating expenses increased primarily due to higher planned maintenance and turnaround costs compared with 2017.

Refining and Marketing – Capital Investment

($ millions)	2018	2017	2016
Wood River Refinery	**119**	114	147
Borger Refinery	**85**	54	66
Marketing	**4**	12	7
	208	180	220

Capital expenditures in 2018 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.

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. Refining and Marketing DD&A was $222 million in 2018 compared with $215 million in 2017.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by Cenovus's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains and losses, if any, on interest rate swaps and foreign exchange contracts. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. The Corporate and Eliminations segment also includes Cenovus-wide costs for general and administrative, onerous contract provisions, finance costs, interest income, foreign exchange (gain) loss, revaluation (gain), transaction costs, re-measurement of the contingent payment, research costs, (gain) loss on divestiture of assets, and other (income) loss.

In 2018, our risk management activities resulted in:

- Unrealized risk management gains of $1,249 million (2017 – losses of $729 million);
- Realized risk management gains of $23 million on interest rate swaps (2017 – $nil); and
- Realized risk management losses of $1 million on foreign exchange contracts (2017 – gains of $146 million).

($ millions)	**2018**	2017	2016
General and Administrative	**391**	300	318
Onerous Contract Provisions	**629**	8	8
Finance Costs	**627**	645	390
Interest Income	**(19)**	(62)	(52)
Foreign Exchange (Gain) Loss, Net	**854**	(812)	(198)
Revaluation (Gain)	**-**	(2,555)	-
Transaction Costs	**-**	56	-
Re-measurement of Contingent Payment	**50**	(138)	-
Research Costs	**25**	36	36
(Gain) Loss on Divestiture of Assets	**795**	1	6
Other (Income) Loss, Net	**(12)**	(5)	34
	3,340	(2,526)	542

Expenses

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs and office rent. In 2018, general and administrative costs increased by $91 million, primarily driven by severance costs of $60 million related to workforce reductions, higher rent costs, and an increase in long-term employee incentive costs related to a smaller decrease in our share price as compared with the decrease in 2017, partially offset by $40 million of transition costs related to the Acquisition that were recorded in 2017.

Onerous Contract Provisions

The provision for onerous contracts relates to onerous operating leases and operating costs for office space in Calgary, Alberta. The provision represents the present value of the difference between the future lease payments that we are obligated to make under the non-cancellable lease contracts and the estimated sublease recoveries, discounted at our credit-adjusted risk-free rate. For the year ended December 31, 2018, we recorded a non-cash provision for onerous contracts of $629 million (net of $57 million due to the change in the credit-adjusted risk-free discount rate) compared with $8 million in 2017.

We are actively managing our real estate portfolio, and in the third quarter of 2018, we reached an agreement to sublease a portion of our Calgary office space that was in excess of our current and near-term requirements.

Finance Costs

Finance costs include interest expense on our short-term borrowings and long-term debt as well as the unwinding of the discount on decommissioning liabilities. On October 29, 2018, we redeemed US$800 million of our US$1,300 million unsecured notes due October 15, 2019, resulting in a redemption premium of US$20 million and associated unamortized discount and debt issue costs of $1 million that were recognized as finance costs.

In December 2018, we paid US$69 million to repurchase unsecured notes with a principal amount of US$76 million. A gain of $9 million on the repurchase was recorded in finance costs. Subsequent to December 31, 2018, we repurchased a further US$324 million of unsecured notes for cash of US$300 million.

Finance costs decreased by $18 million in 2018 compared with 2017 due a reduction in total debt, resulting in lower interest expense, partially offset by the premium on redemption of long-term debt. In 2017, finance costs were higher primarily due to costs associated with additional debt incurred to finance the Acquisition, including $3.6 billion borrowed under a committed Bridge Facility that was fully repaid and retired in December 2017.

The weighted average interest rate on outstanding debt for 2018 was 5.1 percent (2017 – 4.9 percent).

Foreign Exchange

($ millions)	**2018**	2017	2016
Unrealized Foreign Exchange (Gain) Loss	**649**	(857)	(189)
Realized Foreign Exchange (Gain) Loss	**205**	45	(9)
	854	(812)	(198)

In 2018, unrealized foreign exchange losses were recorded primarily as a result of the translation of our U.S. dollar denominated debt. At December 31, 2018, the Canadian dollar relative to the U.S. dollar was eight percent weaker compared with December 31, 2017, creating unrealized losses in 2018.

Revaluation (Gain)

Prior to the Acquisition, our 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11, *"Joint Arrangements"* and as such Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, we control FCCL, as defined under IFRS 10, *"Consolidated Financial Statements"* and accordingly, FCCL has been consolidated. As required by IFRS 3, "*Business Combinations*" when control is achieved in stages, the previously held interest in FCCL was re-measured to its fair value of $12.3 billion and a non-cash revaluation gain of $2.6 billion ($1.9 billion, after-tax) was recorded in our 2017 net earnings.

Transaction Costs

In 2017, we expensed $56 million of transaction costs related to the Acquisition.

Re-measurement of Contingent Payment

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

The contingent payment is accounted for as a financial option. The fair value of $132 million as at December 31, 2018 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the year ended December 31, 2018, a non-cash re-measurement loss of $50 million was recorded.

As at December 31, 2018, average WCS forward pricing for the remaining term of the contingent payment is C$38.87 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$35.60 per barrel and C$41.60 per barrel. For the year ended December 31, 2018, $124 million was payable under the contingent payment agreement (2017 – $17 million).

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2018 was $58 million (2017 – $62 million).

Income Tax

($ millions)	**2018**	2017	2016
Current Tax			
Canada	**(128)**	(217)	(260)
United States	**2**	(38)	1
Current Tax Expense (Recovery)	**(126)**	(255)	(259)
Deferred Tax Expense (Recovery)	**(884)**	203	(84)
Total Tax Expense (Recovery) From Continuing Operations	**(1,010)**	(52)	(343)

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

($ millions)	**2018**	2017	2016
Earnings (Loss) From Continuing Operations Before Income Tax	**(3,926)**	2,216	(802)
Canadian Statutory Rate (percent)	**27.0**	27.0	27.0
Expected Income Tax Expense (Recovery) From Continuing Operations	**(1,060)**	598	(217)
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(57)**	(17)	(46)
Non-Taxable Capital (Gains) Losses	**82**	(129)	(26)
Non-Recognition of Capital (Gains) Losses	**99**	(99)	(26)
Adjustments Arising From Prior Year Tax Filings	**3**	(41)	(46)
Recognition of Previously Unrecognized Capital Losses	**-**	(68)	-
Recognition of U.S. Tax Basis	**(78)**	-	-
Change in U.S. Statutory Rate	**-**	(275)	-
Non-Deductible Expenses	**2**	(5)	5
Other	**(1)**	(16)	13
Total Tax Expense (Recovery) From Continuing Operations	**(1,010)**	(52)	(343)
Effective Tax Rate (percent)	**25.7**	(2.3)	42.8

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review and as a result, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

In 2017 and 2018, cash tax recoveries were recorded associated with prior year taxes paid. The maximum recovery was reached in 2018 and we expect cash tax expense in 2019.

In 2018, we recorded a deferred tax recovery related to current period losses, including the write down of the Deep Basin E&E assets, and a $78 million recovery arising from an adjustment to the tax basis of our refining assets. The increase in tax basis was a result of our partner recognizing a taxable gain on their interest in WRB Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. A deferred tax expense on continuing operations was recorded in 2017 due to the revaluation gain of our pre-existing interest in connection with the Acquisition, net of a tax benefit related to the reduction of the US federal corporate tax rate from 35 percent to 21 percent.

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 losses.

DISCONTINUED OPERATIONS

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

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. A before-tax gain on discontinuance of $343 million was recorded on the sale.

The divestitures completed in 2017 generated total gross cash proceeds of $3.2 billion before closing adjustments and a before-tax gain of $1.3 billion.

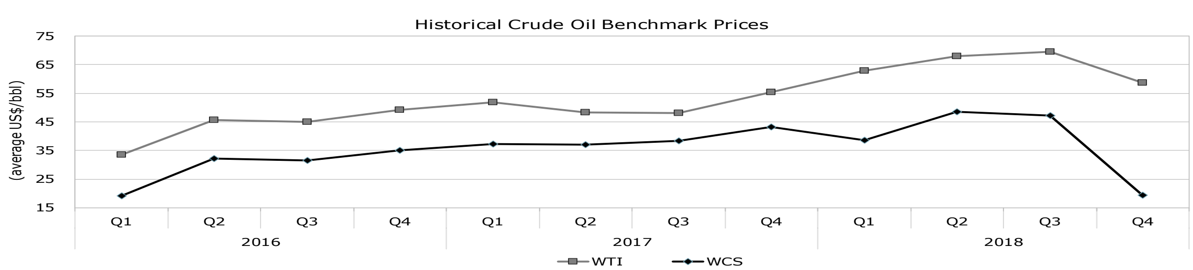
Financial Results

($ millions)	**2018**	2017	2016
Gross Sales	**14**	1,309	1,267
Less: Royalties	**3**	174	139
Revenues	**11**	1,135	1,128
Expenses			
Transportation and Blending	**1**	167	186
Operating	**(28)**	426	444
Production and Mineral Taxes	**1**	18	12
(Gain) Loss on Risk Management	**-**	33	(58)
Operating Margin	**37**	491	544
Depreciation, Depletion and Amortization	**-**	192	567
Exploration Expense	**-**	2	-
Finance Costs	**1**	80	102
Earnings (Loss) From Discontinued Operations Before Income Tax	**36**	217	(125)
Current Tax Expense (Recovery)	**-**	24	86
Deferred Tax Expense (Recovery)	**9**	33	(125)
After-tax Earnings (Loss) From Discontinued Operations	**27**	160	(86)
After-tax Gain (Loss) on Discontinuance [(1)]	**220**	938	-
Net Earnings (Loss) From Discontinued Operations	**247**	1,098	(86)

(1) *Net of $81 million deferred tax expense in the year ended December 31, 2018 (2017 – $347 million deferred tax expense).*

QUARTERLY RESULTS

Our results over the last eight quarters were impacted primarily by volatility in commodity prices, as well as the increase to production volumes due to the Acquisition. Light oil benchmark prices improved through the majority of 2018; however, market conditions resulted in a substantial fall in the price of WTI in the fourth quarter of 2018, ending the year more than 20 percent below where it started in January 2018. At the same time, light-heavy crude oil differentials increased significantly, most prominently in the fourth quarter of 2018 when the differential between WTI and WCS benchmark prices hit a record of US$52.00 per barrel. As a result, our companywide Netback from continuing operations averaged negative $1.13 per BOE in the fourth quarter of 2018, before realized risk management activities, a substantial decrease from $22.38 per BOE in the fourth quarter of 2017.



Selected Operating and Consolidated Financial Results

($ millions, except per share amounts or where otherwise indicated)	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3	2017 Q2	2017 Q1
Production Volumes								
Liquids (barrels per day)	**354,592**	408,950	423,340	395,474	422,157	449,055	333,664	234,914
Natural Gas (MMcf per day)	**469**	520	572	558	795	851	620	363
Total Production (BOE per day)	**432,714**	495,608	518,609	488,561	554,606	590,851	436,929	295,414
Total Production From Continuing Operations (BOE per day)	**432,713**	495,592	518,530	487,464	480,497	478,817	322,792	184,001
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**477**	492	464	349	450	462	449	406
Refined Products (Mbbls/d)	**502**	518	490	369	480	490	476	433
Revenues	**4,545**	5,857	5,832	4,610	5,079	4,386	4,037	3,541
Operating Margin [(1)]								
From Continuing Operations	**135**	1,191	911	157	1,018	1,097	572	305
Total Operating Margin	**132**	1,192	938	169	1,088	1,214	731	450
Cash From Operating Activities								
From Continuing Operations	**488**	1,258	506	(134)	833	481	1,102	195
Total Cash From Operating Activities	**485**	1,259	533	(123)	900	592	1,239	328
Adjusted Funds Flow [(2)]								
From Continuing Operations	**(33)**	976	747	(53)	796	865	603	183
Total Adjusted Funds Flow	**(36)**	977	774	(41)	866	980	745	323
Operating Earnings (Loss) [(2)]								
From Continuing Operations	**(1,670)**	(41)	(292)	(752)	(533)	240	298	(39)
Per Share ($) [(3)]	**(1.36)**	(0.03)	(0.24)	(0.61)	(0.43)	0.20	0.27	(0.05)
Total Operating Earnings (Loss)	**(1,672)**	(42)	(272)	(743)	(514)	327	352	(39)
Per Share ($) [(3)]	**(1.36)**	(0.03)	(0.22)	(0.60)	(0.42)	0.27	0.32	(0.05)
Net Earnings (Loss)								
From Continuing Operations	**(1,350)**	(242)	(410)	(914)	(776)	275	2,558	211
Per Share ($) [(3)]	**(1.10)**	(0.20)	(0.33)	(0.74)	(0.63)	0.22	2.30	0.25
Total Net Earnings (Loss)	**(1,356)**	(241)	(418)	(654)	620	(82)	2,617	211
Per Share ($) [(3)]	**(1.10)**	(0.20)	(0.34)	(0.53)	0.50	(0.07)	2.35	0.25
Capital Investment [(4)]								
From Continuing Operations	**276**	271	294	522	557	396	277	225
Total Capital Investment	**276**	271	292	524	583	438	327	313
Dividends								
Cash Dividends	**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

(1) Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements, in Notes 1 and 9 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 PP&E, E&E assets, and assets held for sale.

Fourth Quarter 2018 Results Compared With the Fourth Quarter 2017

Continuing Operations

Production Volumes

Total production from continuing operations decreased 10 percent in the fourth quarter of 2018 compared with 2017. The decrease in production was primarily due to our decision to manage oil sands production rates in response to takeaway capacity constraints and wider heavy oil differentials. Restricting production well rates reduced oil sands production by approximately 51,000 barrels per day in the fourth quarter of 2018 compared with 2017.

Refinery Operations

Crude oil runs and refined product output increased compared with 2017, with both Refineries operating above nameplate capacity.

Revenues

Revenues decreased $534 million in 2018 primarily due to:

- Wider light-heavy crude oil differentials resulting in a 71 percent decrease in our liquids sales prices from continuing operations to $13.26 per barrel; and
- Decreased sales volumes due to lower production.

The decreases above were partially offset by increased refining revenues due to higher realized crack spreads and increased crude utilization rates, higher revenues from third-party crude oil and natural gas sales undertaken by the marketing group, as well as lower crude oil royalties.

Operating Margin

Operating Margin from continuing operations decreased 87 percent in the fourth quarter of 2018 compared with 2017. Upstream Operating Margin decreased by $820 million due to:

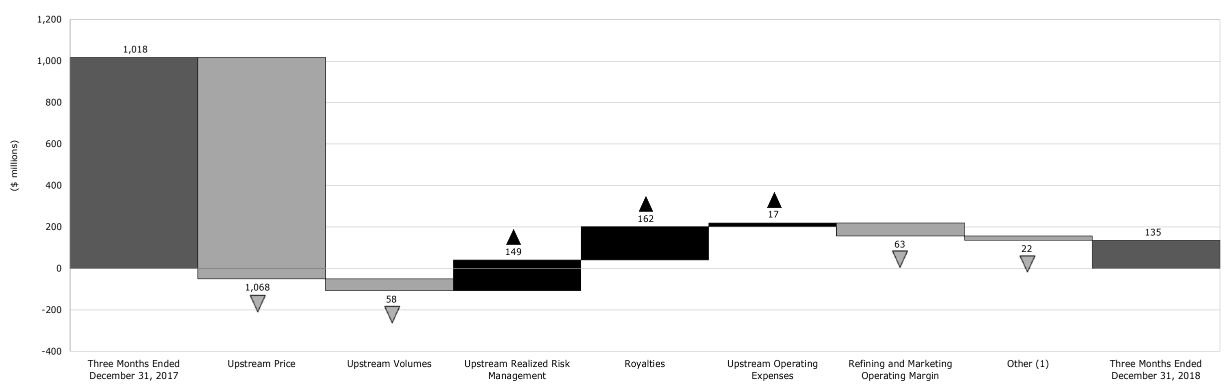
- A decrease in our average liquids sales prices due to wider light-heavy crude oil differentials and higher condensate costs;
- Increased transportation and blending expenses related to an increase in the price of condensate; and
- Decreased sales volumes due to lower production.

These decreases were partially offset by:

- Lower royalties primarily due to a lower realized liquids sales price; and
- Realized risk management losses of $86 million compared with losses of $235 million in 2017.

Refining and Marketing Operating Margin decreased by $63 million. The decrease was primarily due to lower average market crack spreads, partially offset by wider WTI-WCS and WTI-WTS differentials, which created a feedstock cost advantage, a reduction in the cost of RINs, higher realized margins on refined products, and improved crude utilization rates at both Refineries.

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.*

Discontinued Operations

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta. As a result, there was no production in the fourth quarter of 2018 compared with 74,109 BOE per day in 2017.

Consolidated Results

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow decreased in the fourth quarter of 2018 compared with 2017, primarily due to lower Operating Margin, as discussed above. The decrease in Cash From Operating Activities was partially offset by changes in non-cash working capital.

The change in non-cash working capital in the fourth quarter of 2018 was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable and income tax payable. For 2017, the change in non-cash working capital was primarily due to an increase in accounts payable and income tax payable, partially offset by an increase in accounts receivable and inventory.

Operating Earnings (Loss)

Operating Earnings from continuing operations decreased $1,137 million in the three months ended December 31, 2018 compared with 2017. The decrease was primarily due to exploration expense of $2.1 billion in the fourth quarter of 2018 compared with $887 million in 2017, as well as lower Cash From Operating Activities and Adjusted Funds Flow, as discussed above. These decreases were partially offset by a deferred income tax recovery of $705 million compared with a recovery of $201 million in 2017, a re-measurement gain on the contingent payment of $361 million compared with $29 million in the fourth quarter of 2017, and lower DD&A.

Discontinued operations recorded an Operating Loss of $2 million in the fourth quarter of 2018 compared with Operating Earnings of $19 million in the same period of 2017.

Net Earnings (Loss)

Net loss from continuing operations of $1,350 million for the three months ended December 31, 2018 compared with a net loss of $776 million in 2017. The change was primarily due to lower operating earnings, as discussed above, partially offset by unrealized risk management gains of $741 million compared with losses of $654 million in 2017. In addition, a deferred tax recovery of $275 million was recorded in the fourth quarter of 2017 to reflect the benefit of the decreased U.S. federal corporate income tax rate, and non-operating unrealized foreign exchange losses of $296 million compared with losses of $51 million in 2017.

Net earnings from discontinued operations in the fourth quarter of 2017 includes a $1,378 million after-tax gain on the divestiture of our Conventional segment assets.

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2018 was $276 million, a decrease of $281 million from 2017. The decrease was primarily due to our continued focus on capital discipline and reduced activity in the Deep Basin relative to 2017.

Capital investment from discontinued operations was $nil in the fourth quarter of 2018 compared with $26 million in 2017 as a result of the decision to divest our legacy Conventional assets.

OIL AND GAS RESERVES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy crude oil, light and medium oil, NGLs, conventional natural gas and shale gas proved and probable reserves. For disclosure purposes, we have included heavy crude oil with bitumen and shale gas with conventional natural gas, as the reserves of heavy crude oil and shale gas were not material in 2018, following the divestitures of Suffield on January 5, 2018 and CPP on September 6, 2018.

Developments in 2018 compared with 2017 include:

- Bitumen proved reserves increased by 66 million barrels as additions from the recognition of lower continuous net pay thickness cut-offs in Oil Sands and a minor Alberta Energy Regulator ("AER") approved area expansion at Foster Creek, as well as improved performance in Oil Sands more than offset reductions due to the divestiture of Suffield (heavy crude oil) and current year production;
- Bitumen proved plus probable reserves increased by 19 million barrels as additions due to the recognition of lower continuous net pay thickness cut-offs and improved performance in Oil Sands were partially offset by reductions due to the divestiture of Suffield (heavy crude oil) and current year production;
- Light and medium oil proved reserves and proved plus probable reserves decreased by one million barrels and two million barrels, respectively, as minor additions were more than offset by reductions due to the divestiture of CPP and current year production;
- NGLs proved and proved plus probable reserves decreased by 31 million barrels and 55 million barrels, respectively, as additions attributed to Deep Basin development were more than offset by reductions due to the divestiture of CPP, technical revisions attributed to changes to future Deep Basin development plans, and current year production; and
- Conventional natural gas proved and proved plus probable reserves decreased by 596 billion cubic feet and 702 billion cubic feet, respectively, as additions attributed to Deep Basin development were more than offset by reductions due to the divestiture of CPP, technical revisions attributed to changes to the Deep Basin development plans, and current year production.

The reserves data that follows is presented as at December 31, 2018 using an average of forecasts ("IQRE Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. The IQRE Average Forecast prices and costs are dated January 1, 2019. Comparative information as at December 31, 2017 uses the January 1, 2018 IQRE Average Forecast prices and costs.

Reserves

As at December 31, 2018 (before royalties)	Bitumen [1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [2] (Bcf)	Total (MMBOE)
Proved	**4,831**	**12**	**72**	**1,513**	**5,167**
Probable	**1,598**	**5**	**44**	**1,041**	**1,821**
Proved plus Probable	**6,429**	**17**	**116**	**2,554**	**6,988**

(1) Includes heavy crude oil reserves that are not material.
(2) Includes shale gas reserves that are not material.

Reconciliation of Proved Reserves

(before royalties)	Bitumen [1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [2] (Bcf)	Total (MMBOE)
December 31, 2017	**4,765**	**13**	**103**	**2,109**	**5,232**
Extensions and Improved Recovery	**131**	**2**	**11**	**210**	**179**
Discoveries	**-**	**-**	**-**	**-**	**-**
Technical Revisions	**81**	**-**	**(3)**	**(29)**	**74**
Economic Factors	**-**	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**	**-**
Dispositions	**(13)**	**(1)**	**(30)**	**(582)**	**(141)**
Production [3]	**(133)**	**(2)**	**(9)**	**(195)**	**(177)**
December 31, 2018	**4,831**	**12**	**72**	**1,513**	**5,167**
Year Over Year Change	**66**	**(1)**	**(31)**	**(596)**	**(65)**
Year Over Year Change (percent)	**1**	**(8)**	**(30)**	**(28)**	**(1)**

(1) Includes heavy crude oil reserves that are not material.
(2) Includes shale gas reserves that are not material.
(3) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.

Reconciliation of Proved Plus Probable Reserves

(before royalties)	Bitumen [1] (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [2] (Bcf)	Total (MMBOE)
December 31, 2017	**6,410**	**19**	**171**	**3,256**	**7,142**
Extensions and Improved Recovery	**105**	**3**	**25**	**515**	**220**
Discoveries	**-**	**-**	**-**	**-**	**-**
Technical Revisions	**64**	**(2)**	**(8)**	**(138)**	**32**
Economic Factors	**-**	**-**	**-**	**-**	**-**
Acquisitions	**-**	**-**	**-**	**-**	**-**
Dispositions	**(17)**	**(1)**	**(63)**	**(884)**	**(229)**
Production [3]	**(133)**	**(2)**	**(9)**	**(195)**	**(177)**
December 31, 2018	**6,429**	**17**	**116**	**2,554**	**6,988**
Year Over Year Change	**19**	**(2)**	**(55)**	**(702)**	**(154)**
Year Over Year Change (percent)	**-**	**(11)**	**(32)**	**(22)**	**(2)**

(1) Includes heavy crude oil reserves that are not material.
(2) Includes shale gas reserves that are not material.
(3) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.

Additional information with respect to the evaluation and reporting of our reserves in accordance with National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101") is contained in our AIF for the year ended December 31, 2018. Our AIF is available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in this MD&A in the "Risk Management and Risk Factors" section.

LIQUIDITY AND CAPITAL RESOURCES

($ millions)	2018	2017	2016
Cash From (Used In)			
Operating Activities – Continuing Operations	**2,118**	2,611	426
Operating Activities – Discontinued Operations	**36**	448	435
Total Operating Activities	**2,154**	3,059	861
Investing Activities – Continuing Operations	**(1,017)**	(15,859)	(911)
Investing Activities – Discontinued Operations	**404**	2,993	(168)
Total Investing Activities	**(613)**	(12,866)	(1,079)
Net Cash Provided (Used) Before Financing Activities	**1,541**	(9,807)	(218)
Financing Activities	**(1,410)**	6,515	(168)
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**40**	182	1
Increase (Decrease) in Cash and Cash Equivalents	**171**	(3,110)	(385)

As at December 31,	2018	2017	2016
Cash and Cash Equivalents	**781**	610	3,720
Committed and Undrawn Credit Facility	**4,500**	4,500	4,000

Cash From (Used In) Operating Activities

Cash from operating activities decreased in 2018 mainly due to lower Operating Margin, as discussed in the Financial Results section of this MD&A, a decrease in current income tax recovery and higher general and administrative costs, primarily due to $60 million of severance costs, as well as increased rent costs. In 2017, we benefited from realized risk management gains of $146 million on foreign exchange contracts, partially offset by transaction costs of $56 million related to the Acquisition. These decreases were partially offset by changes in non-cash working capital, as discussed in the Financial Results section of this MD&A.

Excluding risk management assets and liabilities, assets and liabilities held for sale, the current portion of the contingent payment, and onerous contract provisions, our working capital was $500 million at December 31, 2018 compared with $1,141 million at December 31, 2017. Working capital declined primarily due to the current portion of the $682 million of unsecured notes due on October 15, 2019. The decline in working capital was also due to lower accounts receivable and inventory, partially offset by a decrease in accounts payable.

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

Cash From (Used In) Investing Activities

Cash used in investing activities was lower in 2018 primarily due to the Acquisition in 2017.

Cash From (Used In) Financing Activities

In 2018, cash was used in financing activities primarily for the repayment of $1.1 billion of debt, as well as dividends paid on common shares. In 2017, cash was generated by financing activities from the issuance of debt and common shares to finance the Acquisition.

In 2018, we redeemed US$800 million of our US$1,300 million unsecured notes due on October 15, 2019. We also paid US$69 million to repurchase a portion of our unsecured notes with a principal of US$76 million. As at December 31, 2018 we had US$6,774 million in U.S. dollar debt ($9,241 million) compared with US$7,650 million ($9,597 million) at December 31, 2017.

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

Dividends

In 2018, we paid dividends of $0.20 per common share or $245 million (2017 – 0.20 per common share or $225 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 December 31, 2018:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**781**
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 and $3.3 billion tranche. In the fourth quarter of 2018, we amended the committed credit facility to extend the maturity date of the $1.2 billion tranche to November 30, 2021 and the $3.3 billion tranche to November 30, 2022. As of December 31, 2018, 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 December 31, 2018, US$4.6 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted EBITDA and Net Debt to Capitalization. We define our non-GAAP measure of Net Debt as short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, 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 12-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

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

The following is a reconciliation of Adjusted EBITDA, and the calculation of Net Debt to Adjusted EBITDA:

As at December 31,	2018	2017	2016
Current Portion of Long-Term Debt	**682**	-	-
Long-Term Debt	**8,482**	9,513	6,332
Less: Cash and Cash Equivalents	**(781)**	(610)	(3,720)
Net Debt	**8,383**	8,903	2,612
Net Earnings (Loss)	**(2,669)**	3,366	(545)
Add (Deduct):			
Finance Costs	**628**	725	492
Interest Income	**(19)**	(62)	(52)
Income Tax (Recovery) Expense	**(920)**	352	(382)
DD&A	**2,131**	2,030	1,498
E&E Write-down	**2,123**	890	2
Unrealized (Gain) Loss on Risk Management	**(1,249)**	729	554
Foreign Exchange (Gain) Loss, Net	**854**	(812)	(198)
Revaluation (Gain)	**-**	(2,555)	-
Re-measurement of Contingent Payment	**50**	(138)	-
(Gain) Loss on Discontinuance	**(301)**	(1,285)	-
(Gain) Loss on Divestiture of Assets	**795**	1	6
Other (Income) Loss, Net	**(12)**	(5)	34
Adjusted EBITDA (1)	**1,411**	3,236	1,409
Net Debt to Adjusted EBITDA	**5.9x**	2.8x	1.9x

(1) *Calculated on a trailing 12-month basis. Includes discontinued operations.*

Net Debt to Capitalization is calculated as follows:

As at December 31,	**2018**	2017	2016
Net Debt	**8,383**	8,903	2,612
Shareholders' Equity	**17,468**	19,981	11,590
Capitalization	**25,851**	28,884	14,202
Net Debt to Capitalization [1] (percent)	**32**	31	18

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.

As at December 31, 2018, Cenovus's Net Debt to Adjusted EBITDA is 5.9x, which is above our target. Net debt to Adjusted EBITDA increased as result of lower Adjusted EBITDA due to reasons mentioned in the Financial Results section of this MD&A. This was partially offset by the reduction in our debt levels. On October 29, 2018, we redeemed US$800 million of our US$1,300 million unsecured notes due October 15, 2019. In December 2018, we also paid US$69 million to repurchase our unsecured notes with a principal amount of US$76 million.

Subsequent to December 31, 2018, we repurchased a further US$324 million of unsecured notes for cash of US$300 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 Consolidated Financial Statements.

Share Capital and Stock-Based Compensation Plans

As at December 31, 2018, there were approximately 1,229 million common shares outstanding (2017 – 1,229 million common shares). In the second quarter of 2017, Cenovus closed a bought-deal common share financing of 187.5 million common shares, for gross proceeds of $3.0 billion ($2.9 billion net of $101 million of share issuance costs).

In addition, Cenovus issued 208 million common shares to ConocoPhillips on May 17, 2017 as partial consideration for the Acquisition. In relation to the share consideration, Cenovus and ConocoPhillips entered into an investor agreement, and a registration rights agreement. In accordance with these agreements, ConocoPhillips has certain rights and restrictions, including, among other things, the ability to nominate new members to the Board and the requirement to vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the then outstanding common shares of Cenovus. As at December 31, 2018, ConocoPhillips continued to hold these common shares.

As part of our long-term incentive program, Cenovus has an employee Stock Option Plan as well as Performance Share Unit ("PSU") Plan, a Restricted Share Unit ("RSU") Plan and two Deferred Share Unit ("DSU") Plans. Certain directors, officers or employees chose prior to December 31, 2017 to convert a portion of their remuneration, paid in the first quarter of 2018, into DSUs. The election for any particular year is irrevocable. DSUs may not be redeemed until after departure from Cenovus. Directors also received an annual grant of DSUs.

Refer to Note 30 of the 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 January 31, 2019	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**33,957**	**27,083**
Other Stock-Based Compensation Plans	**15,034**	**1,558**

Contractual Obligations and Commitments

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

($ millions)	Expected Payment Date 2019	2020	2021	2022	2023	Thereafter	Total
Operating							
Transportation and Storage [1]	1,040	1,104	1,335	1,491	1,562	16,809	**23,341**
Operating Leases (Building Leases) [2]	156	150	146	144	141	2,158	**2,895**
Other Long-term Commitments	148	81	45	37	32	147	**490**
Interest on Long-term Debt	470	431	431	431	411	5,993	**8,167**
Decommissioning Liabilities	56	57	34	39	42	2,402	**2,630**
Total Operating	1,870	1,823	1,991	2,142	2,188	27,509	**37,523**
Investing							
Capital Commitments	21	2	1	-	-	-	**24**
Contingent Payment	15	47	66	15	-	-	**143**
Total Investing	36	49	67	15	-	-	**167**
Financing							
Long-term Debt (principal only)	682	-	-	682	614	7,263	**9,241**
Other	-	-	1	-	1	2	**4**
Total Financing	682	-	1	682	615	7,265	**9,245**
Total Payments [3]	2,588	1,872	2,059	2,839	2,803	34,774	**46,935**

(1) Includes transportation commitments of $14 billion that are subject to regulatory approval or have been approved but are not yet in service.
(2) Includes onerous contract provisions.
(3) Contracts on behalf of WRB are reflected at our 50 percent interest.

We have total commitments not included on our balance sheet of $26 billion, of which $23 billion are for various transportation commitments, including $5 billion in new contracts primarily related to Keystone XL, expanded freight and rail terminal and tank contracts. Transportation commitments include $14 billion that are subject to regulatory approval or have been approved but are not yet in service (December 31, 2017 – $9 billion). These agreements are for terms up to 20 years subsequent to the date of commencement and should help align our future transportation requirements with anticipated production growth.

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 December 31, 2018, there were outstanding letters of credit aggregating $336 million issued as security for performance under certain contracts (December 31, 2017 – $376 million).

Legal Proceedings

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

Contingent Payment

In connection with the Acquisition and related to oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at December 31, 2018, the estimated fair value of the contingent payment was $132 million. See the Corporate and Eliminations section of this MD&A for more details.

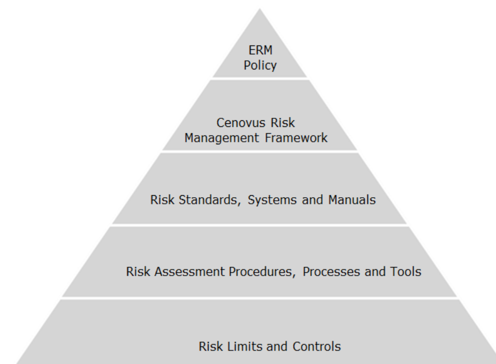
RISK MANAGEMENT AND RISK FACTORS

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.

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of risk across Cenovus and is integrated with the Cenovus Operations Management System ("COMS"). In addition, we continuously monitor our risk profile as well as industry best practices.

Risk Governance

The ERM Policy, approved by our Board, outlines our risk management principles and expectations, as well as the roles and responsibilities of all staff. Building on the ERM Policy, we have established Risk Management Standards, a Risk Management Framework and Risk Assessment Tools. Our Risk Management Framework contains the key attributes recommended by the International Standards Organization ("ISO") in its *ISO 31000 – Risk Management Guidelines (2017)*. The results of our ERM program are documented in an Annual Risk Report presented to the Board as well as through regular updates.



Risk Assessment

All risks are assessed for their potential impact on the achievement of Cenovus's strategic objectives as well as their likelihood of occurring. Risks are analyzed through the use of a Risk Matrix and other standardized risk assessment tools and each risk is classified on a continuum ranging from "Low" to "Extreme". Management determines what, if any, additional risk treatment is required based on the residual risk ranking. There are prescribed actions for escalating and communicating risk to the right decision makers.

Significant Risk Factors

The following discussion describes the financial, operational, regulatory, environmental, reputational and other risks related to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on our business, financial condition, results of operations, cash flows, or reputation.

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions. Financial risks include, but are not limited to: fluctuations in commodity prices; development and operating costs; risks related to Cenovus's hedging activities; exposure to counterparties; availability of capital and access to sufficient liquidity; risks related to Cenovus's credit ratings; fluctuations in foreign exchange and interest rates. In addition, we identify risks related to our ability to pay a dividend to shareholders; and risks related to internal controls for financial reporting. Changes in financial management and/or market conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, financial condition, results of operations and growth, the maintenance of our existing operations and business plans, financial strength of our counterparties, access to capital and cost of borrowing.

Commodity Prices

Our financial performance is significantly dependent on the prevailing prices of crude oil, natural gas and refined products. Crude oil prices are impacted by a number of factors including, but not limited to: the supply of and demand for crude oil; global economic conditions; the actions of OPEC including, without limitation, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC not to impose production quotas on its members; actions by the Government of Alberta including, without limitation, imposing, amending, or lifting crude oil production curtailments, and compliance or non-compliance with imposed crude oil production curtailments; enforcement of government or environmental regulations; political stability; market access constraints and transportation interruptions (pipeline, marine or rail); the availability of alternate fuel sources; and weather conditions. Natural gas prices are impacted by a number of factors including, but not limited to: North American supply and demand; developments related to the market for liquefied natural gas; weather conditions; prices of alternate sources of energy; government or environmental regulations; and economic conditions. Refined product prices are impacted by a number of factors including, but not limited to: global supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; weather conditions; and the availability of alternate fuel sources. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance is also impacted by discounted or reduced commodity prices for our oil production relative to certain international benchmark prices, due, in part, to constraints on the ability to transport and sell products to international markets and the quality of oil produced. Of particular importance to us are diluent cost and supply and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore trades at a discount to the market price for light and medium crude oil and heavy crude oil.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to seasonal factors as production changes to match seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business.

Fluctuations in the price of commodities, associated price differentials and refining margins may impact the value of our assets, our cash flows, our ability to maintain our business and to fund growth projects including, but not limited to, the continued development of our oil sands properties. Prolonged periods of commodity price volatility may also negatively impact our ability to meet guidance targets and meet all of our financial obligations as they come due. Any substantial decline in these commodity prices or extended period of low commodity prices may result in a delay or cancellation of existing or future drilling, development or construction programs, curtailment in production (independent of any crude oil production curtailment mandated by the Government of Alberta and then in effect), unutilized long-term transportation commitments and/or low utilization levels at Cenovus's refineries.

The commodity price risks noted above, as well as the other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, that may have a material impact on our business, financial condition, results of operations, cash flows or reputation, may be considered to be indicators of impairment. Another indication of impairment is the comparison of the carrying value of our assets to our market capitalization.

As discussed in this MD&A, we conduct an annual assessment of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas prices decline significantly and remain at low levels for an extended period of time, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

Development and Operating Costs

Our financial performance is significantly affected by the cost of developing and operating our assets. Development and operating costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies; inflationary price pressure; scheduling delays; failure to maintain quality construction and manufacturing standards; and supply chain disruptions, including access to skilled labour. Electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating costs that are susceptible to significant fluctuation.

Hedging Activities

Cenovus's Market Risk Mitigation Policy, which has been approved by the Board, allows Management to use derivative instruments to help mitigate the impact of changes in oil and natural gas prices, crude oil differentials, diluent or condensate supply prices and differentials, refining margins, power prices, as well as fluctuations in foreign exchange rates and interest rates. Cenovus also uses derivative instruments in various operational markets to help optimize our supply costs or sales of our production.

The use of such hedging activities exposes us to risks which may cause significant loss. These risks include, but are not limited to: changes in the valuation of the hedge instrument being not well correlated to the change in the valuation of the underlying exposures being hedged; change in price of the underlying commodity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; and the unenforceability of contracts.

There is risk that the consequences of hedging to protect against unfavourable market conditions may limit the benefit to us of commodity price increases or changes in interest rates and foreign exchange rates. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil, natural gas or refined products to fulfill our delivery obligations related to the underlying physical transaction.

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 utilized within the refining business 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 3, 33 and 34 to the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

($ millions)	2018 Realized	2018 Unrealized	2018 Total	2017 Realized	2017 Unrealized	2017 Total
Crude Oil [(1)]	**1,577**	**(1,219)**	**358**	307	716	1,023
Refining	**(1)**	**(5)**	**(6)**	6	-	6
Interest Rate	**(23)**	**(26)**	**(49)**	-	13	13
Foreign Exchange	**1**	**1**	**2**	(146)	-	(146)
(Gain) Loss on Risk Management	**1,554**	**(1,249)**	**305**	167	729	896
Income Tax Expense (Recovery)	**(422)**	**336**	**(86)**	(60)	(197)	(257)
(Gain) Loss on Risk Management, After Tax	**1,132**	**(913)**	**219**	107	532	639

(1) 2017 excludes $33 million of realized risk management losses on crude oil contracts from our Conventional segment, which have been classified as a discontinued operation.

In 2018, we incurred realized losses on crude oil risk management activities as the settlement prices exceeded our contract prices. The majority of these hedging contracts were established to provide downside protection and support financial resilience following the Acquisition. These hedging contracts have now expired.

Unrealized gains were recorded on our crude oil financial instruments in the twelve months ended December 31, 2018 primarily due to the realization of settled positions, while partially offset by losses due to WTI and Brent benchmark price increases.

Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to independent fluctuations in commodity prices, interest rates, and foreign exchange rates with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices and interest rates on risk management positions as at December 31, 2018 could have resulted in unrealized gains (losses) for the year as follows:

	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**(78)**	**80**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**4**	**(4)**
Interest Rate Swaps	± 50 Basis Points	**12**	**(13)**
Foreign Exchange	± $0.05 U.S. per Canadian Dollar Foreign Exchange Rate	**4**	**(4)**

For further information on our risk management positions, see Notes 33 and 34 to the 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.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners and other counterparties in the energy industry and other industries for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations, we may suffer financial losses, delays of our development plans or we may have to forego other opportunities which could materially impact our financial condition or operational results.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn, a change in market fundamentals, business operations or credit rating, or significant unanticipated expenses, may impede our ability to secure and maintain cost-effective financing. An inability to access capital could affect our ability to make future capital expenditures and to meet all of our financial obligations as they come due, potentially creating a material adverse effect on our financial condition, results of operations, ability to comply with various financial and operating covenants, credit ratings and reputation.

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

We mitigate our liquidity risk through the active management of cash and debt by ensuring that we have access to multiple sources of capital.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. We routinely review our covenants and we may make changes to development plans or dividend policy, or take alternative actions to ensure compliance. In the event that we do not comply with such covenants, our access to capital could be restricted or repayment could be accelerated.

Credit Ratings

Our company and our long-term and short-term debt are regularly evaluated by the credit rating agencies. Credit ratings are based on our financial and operational strength and a number of factors not entirely within our control, including conditions affecting the oil and gas industry generally, and the state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded or withdrawn entirely by a rating agency.

A reduction in any of our credit ratings could adversely affect the cost and availability of borrowing, and access to sources of liquidity and capital. A failure by Cenovus to maintain current credit ratings could affect our business relationships with counterparties, operating partners and suppliers.

If one or more of our credit ratings falls below certain ratings floors we may be obligated to post collateral in the form of cash, letters of credit or other financial instruments in order to establish or maintain business arrangements. Additional collateral may be required due to further downgrades below certain ratings floors. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing or having contractual business arrangements terminated.

Foreign Exchange Rates

Fluctuations in foreign exchange rates may affect our results as global prices for crude oil, natural gas and refined products are generally set in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A change in the value of the Canadian dollar relative to the U.S. dollar will increase or decrease revenues, as expressed in Canadian dollars, received from the sale of oil and refined products, and from some of our natural gas sales. In addition, we have chosen to borrow U.S. dollar long-term debt. A change in the value of the Canadian dollar against the U.S. dollar will result in an increase or decrease in our U.S. dollar denominated debt and related interest expense, as expressed in Canadian dollars.

We may periodically enter into transactions to manage our exposure to exchange rate fluctuations. Exchange rate fluctuations could have a material adverse effect on our financial condition, results of operations and cash flows.

Interest Rates

We may be exposed to fluctuations in interest rates as a result of the use of floating rate securities or borrowings. An increase in interest rates could increase our net interest expense and affect how certain liabilities are recorded, both of which could negatively impact financial results. Additionally, we are exposed to interest rate fluctuations upon the refinancing of maturing long-term debt and potential future financings at prevailing interest rates.

We may periodically enter into transactions to manage our exposure to interest rate fluctuations.

Ability to Pay Dividends

The payment of dividends is at the discretion of the Board. Dividend payments are regularly reviewed by the Board and may be increased, reduced or suspended from time to time. Our ability to pay dividends and the actual amount of such dividends is dependent upon, among other things, financial performance, debt covenants, satisfying solvency testing, ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and the risk factors set forth in this MD&A.

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

Based on their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Operational Risk

Operational risks are those risks that affect our ability to continue operations in the ordinary course of business. Our operations are subject to risks generally affecting the oil and gas and refining industries. To partially mitigate our risks, we have a system of standards, practices and procedures called COMS to identify, assess and mitigate safety, operational and environmental risk across our operations. In addition to leveraging COMS, we attempt to partially mitigate operational risks by maintaining a comprehensive insurance program in respect of our assets and operations.

Health and Safety

The operation of our properties is subject to hazards of finding, recovering, transporting and processing hydrocarbons including, but not limited to: blowouts; fires; explosions; railcar incident or derailment; gaseous leaks; migration of harmful substances; oil spills; corrosion; acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. Any of these hazards can interrupt operations, impact our reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, cause environmental damage that may include polluting water, land or air, and may result in fines, civil suits, or criminal charges against Cenovus, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows, and our reputation.

Market Access Constraints and Transportation Restrictions

Our production is transported through various pipelines and our refineries are reliant on various pipelines to receive feedstock. Disruptions in, or restricted availability of, pipeline service and/or marine or rail transport, could adversely affect crude oil and natural gas sales, projected production growth, upstream or refining operations and cash flows.

Interruptions or restrictions in the availability of these pipeline systems may also limit the ability to deliver production volumes and could adversely impact commodity prices, sales volumes and/or the prices received for our products. These interruptions and restrictions may be caused by the inability of the pipeline to operate, or they may be related to capacity constraints as the supply of feedstock into the system exceeds the infrastructure capacity. There can be no certainty that investments in new pipeline projects, which would result in an increase in long-term takeaway capacity, will be made by applicable third-party pipeline providers or that any applications to expand capacity will receive the required regulatory approval, or that any such approvals will result in the construction of the pipeline project. There is also no certainty that short-term operational constraints on the pipeline system, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail, marine transport and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on the pipeline system. In addition, our crude-by-rail and marine shipments may be impacted by service delays, inclement weather, railcar availability, railcar derailment or other rail or marine transport incidents and could adversely impact crude oil sales volumes or the price received for product or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property, or environmental damage. In addition, new regulations, which will be phased in over time until 2025, will require tank cars used to transport crude oil by rail to be replaced with newer tank cars, or to be retrofitted to meet the same standards. The costs of complying with the new standards, or any further revised standards, will likely be passed on to rail shippers and may adversely affect our ability to transport crude-by-rail or the economics associated with rail transportation. Finally, planned or unplanned shutdowns or closures of our refinery customers may limit our ability to deliver product with negative implications on sales and cash from operating activities.

On January 30, 2018, the British Columbia Minister of Environment and Climate Change Strategy announced proposed regulatory measures that would limit increases of diluted bitumen being transported through the province while an advisory panel studies if and how heavy oil can be transported safely. It is not clear at this time how or when the restrictions will be implemented, but they could have a material adverse impact on our ability to transport diluted bitumen through British Columbia.

Insufficient transportation capacity for our production will impact our ability to efficiently access end markets. This may negatively impact our financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations or for specific grades of crude oil, and, in extreme situations, production curtailment.

Operational Considerations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; explosions; blowouts; gaseous leaks; power outages; migration of harmful substances into water systems; oil spills; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; equipment failures and other accidents; adverse weather conditions; pollution; and other environmental risks.

Producing and refining oil requires high levels of investment and involves particular risks and uncertainties. Our oil operations are susceptible to loss of production, slowdowns, shutdowns, or restrictions on our ability to produce higher value products due to the interdependence of our component systems. Delineation of the resources, the costs associated with production, including drilling wells for SAGD operations, and the costs associated with refining oil can entail significant capital outlays. The operating costs associated with oil production are largely fixed in the short-term and, as a result, operating costs per unit are largely dependent on levels of production.

Although we are not the operator of the two U.S. refineries in which we have a 50 percent interest, the refining and marketing business is subject to all of the risks inherent in the operation of refineries, terminals, pipelines and other transportation and distribution facilities including, but not limited to: loss of product; failure to follow operating procedures or operate within established operating parameters; slowdowns due to equipment failure or transportation disruptions; railcar incidents or derailments; marine transport incidents; weather; fires and/or explosions; unavailability of feedstock; and price and quality of feedstock.

We do not insure against all potential occurrences and disruptions and it cannot be guaranteed that insurance will be sufficient to cover any such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control.

Reserves Replacement and Reserve Estimates

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves.

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including environmental regulations and royalty payments and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail transportation and processing facilities, all of which may cause actual results to vary materially from estimated results.

All such estimates are to some degree uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves that may be developed and produced in the future are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based on production history will result in variations, which may be material, in the estimated reserves.

The production rate of oil and gas properties tends to decline as reserves are depleted while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, developing and producing oil and natural gas; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties. Our business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and adding additional reserves.

Cost Management

Our operating costs could escalate and become uncompetitive due to inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, higher steam-to-oil ratios in our oil sands operations, and additional government or environmental regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial condition, results of operations and cash flows.

Competition

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new and existing sources of supply, the acquisition of crude oil and natural gas interests and the refining, distribution and marketing of petroleum products. We compete with other producers and refiners, some of which may have lower operating costs or greater resources than our company does. Competing producers may develop and implement recovery techniques and technologies which are superior to those we employ. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

Companies may announce plans to enter the oil sands business, to begin production or to expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of crude oil in the marketplace which may decrease the market price of crude oil, constrain transportation and increase our input costs for and constrain the supply of skilled labour and materials.

Project Execution

There are risks associated with the execution and operation of our upstream growth and development projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable terms or to be granted access within land-use agreements; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; risk related to the accuracy of project cost estimates; ability to finance growth; ability to source or complete strategic transactions; and the effect of changing government regulation and public expectations in relation to the impact of oil sands and conventional development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Partner Risks

Some of our assets are not operated by us or are held in partnership with others. Therefore, our results of operations and cash flows may be affected by the actions of third-party operators or partners. Our refining assets are held in a partnership with Phillips 66 and operated by Phillips 66. The success of the refining operations is dependent on the ability of Phillips 66 to successfully operate this business and maintain the refining assets. We rely on the judgment and operating expertise of Phillips 66 in respect of the operation of such refining assets and we also rely on Phillips 66 to provide information on the status of such refining assets and related results of operations.

Phillips 66 may have objectives and interests that do not align with or may conflict with our interests. Major capital decisions affecting these refining assets require agreement between each respective partner, while certain operational decisions may be made by the operator of the assets. While we generally seek consensus with respect to major decisions concerning the direction and operation of these refining assets, no assurance can be provided that the future demands or expectations of either party relating to such assets will be satisfactorily met or met in a timely manner or at all. Unmet demands or expectations by either party or demands and expectations which are not satisfactorily met may affect our participation in the operation of such assets, our ability to obtain or maintain necessary licences or approvals or affect the timing of undertaking various activities.

Technology

Current SAGD technologies for the recovery of bitumen are energy intensive, requiring significant consumption of natural gas in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using this technology. A large increase in recovery costs could cause certain projects that rely on SAGD technology to become uneconomical, which could have a negative effect on our business, financial condition, results of operations and cash flows. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Information Systems

We rely heavily on information technology, such as computer hardware and software systems, in order to properly operate our business. In the event we are unable to regularly deploy software and hardware, effectively upgrade systems and network infrastructure, and take other steps to maintain or improve the efficiency and efficacy of systems, the operation of such systems could be interrupted or result in the loss, corruption, or release of data.

In the ordinary course of business, we collect, use and store sensitive data, including intellectual property, proprietary business information and personal information of our employees and third parties. Despite our security measures, our information systems, technology and infrastructure may be vulnerable to attacks by hackers and/or cyberterrorists or breaches due to employee error, malfeasance or other disruptions, including natural disasters and acts of war. Any such breach could compromise information used or stored on our systems and/or networks and, as a result, the information could be accessed, publicly disclosed, lost or stolen. Any such access, disclosure or other loss of information could result in legal claims or proceedings, liability under laws that protect the privacy of personal information, regulatory penalties, operational disruption, site shut-down, leaks or other negative consequences, including damage to our reputation, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and pace of growth.

Litigation

From time to time, we may be the subject of litigation arising out of our operations. Claims under such litigation may be material or may be indeterminate. Various types of claims may be made including, without limitation, environmental damages, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, patent infringement and employment matters. The outcome of such litigation is uncertain and may materially impact our financial condition or results of operations. Moreover, unfavorable outcomes or settlements of litigation could encourage the commencement of additional litigation. We may also be subject to adverse publicity associated with such matters, regardless of whether we are ultimately found responsible. We may be required to incur significant expenses or devote significant resources in defense against any such litigation.

Aboriginal Land and Rights Claims

Aboriginal groups have claimed aboriginal treaty, title and rights to portions of western Canada, including British Columbia and Alberta, and such claims, if successful, could have a material negative impact on our operations or pace of growth. There exist outstanding Aboriginal and treaty rights claims, which may include Aboriginal title claims, on lands where we operate. No certainty exists that any lands currently unaffected by claims brought by Aboriginal groups will remain unaffected by future claims. Recent outcomes of litigation concerning Aboriginal rights may result in increased claims and litigation activity in the future.

The federal and provincial governments have a duty to consult with Aboriginal people on actions and decisions that may affect the asserted Aboriginal or treaty rights and, in certain cases, accommodate their concerns. The scope of the duty to consult by federal and provincial governments is subject to ongoing litigation. The fulfillment of the duty to consult, and where required accommodate, Aboriginal people may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. Opposition by Aboriginal groups may also negatively impact us in terms of public perception, diversion of Management's time and resources, legal and other advisory expenses, potential blockades or other interference by third parties in our operations, or court-ordered relief impacting operations. Challenges by Aboriginal groups could adversely impact our progress and ability to explore and develop properties.

In May 2016, Canada announced its support for the United Nations Declaration on the Rights of Indigenous Peoples ("UNDRIP"). The principles and objectives of UNDRIP have also been endorsed by the Government of Alberta and the Government of British Columbia. The means of implementation of UNDRIP by government bodies are uncertain and may include an increase in consultation obligations and processes associated with project development, posing risks and creating uncertainty with respect to project regulatory approval timelines and requirements.

Regulatory Risk

Regulatory risk is the risk of loss or lost opportunity resulting from the introduction of, or changes in, regulatory requirements or the failure to secure regulatory approval for upstream or downstream development projects. The implementation of new regulations or the modification of existing regulations could impact our existing and planned projects as well as result in compliance costs, adversely impacting our financial condition, results of operations and cash flows.

The oil and gas industry in general and our operations in particular are subject to regulation and intervention under federal, provincial, territorial, state and municipal legislation in Canada and the U.S. in matters such as, but not limited to: land tenure; permitting of production projects; royalties; taxes (including income taxes); government fees; production rates; environmental protection controls; protection of certain species or lands; provincial and federal land use designations; the reduction of greenhouse gases ("GHGs") and other emissions; the export of crude oil, natural gas and other products; the transportation of crude-by-rail or marine transport; the awarding or acquisition of exploration and production, oil sands or other interests; the imposition of specific drilling obligations; control over the development, abandonment and reclamation of fields (including restrictions on production) and/or facilities; and possibly expropriation or cancellation of contract rights. Changes to government regulation could impact our existing and planned projects or increase capital investment or operating expenses, adversely impacting our financial condition, results of operations and cash flows.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain all necessary licences, permits and other approvals that may be required to carry out certain exploration and development activities on our properties. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder and Aboriginal consultation, environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; habitat assessments; and other commitments or obligations. Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

As a general rule, the current oil and gas asset abandonment, reclamation and remediation ("A&R") liability regime in Alberta limits each party's liability to its proportionate ownership of an asset. In the case where one joint owner of an oil and gas asset becomes insolvent and is unable to fund its required A&R activities associated with such asset, the solvent counterparties can claim the insolvent party's share of the remediation costs against the Orphan Well Association (the "OWA"). The OWA administers orphaned assets and is funded through a levy imposed on licensees, including Cenovus, based on their proportionate share of deemed A&R liabilities for oil and gas facilities, wells and unreclaimed sites in Alberta. British Columbia has a similar liability management regime.

On January 31, 2019, the Supreme Court of Canada released its decision in the case of Redwater Energy Corporation ("Redwater"). Reversing the lower court decisions, the Supreme Court of Canada held that the AER may use the provincial legislative scheme to prevent a trustee in bankruptcy from renouncing a debtor's uneconomic oil and gas assets and require a trustee to satisfy certain environmental obligations in priority to the claims of secured and unsecured creditors.

While it is not yet clear how market participants will respond to the Supreme Court of Canada's decision in Redwater, the decision is anticipated to reduce the availability and increase the cost of credit for borrowers with relatively high levels of A&R obligations within their asset bases, thereby negatively affecting the financial capacity of such borrowers, including potential counterparties to Cenovus, result in additional or more stringent A&R related covenants being imposed on borrowers, and result in increased scrutiny of oil and gas assets and associated A&R liabilities.

Following the lower court decisions in Redwater, changes were made to the regulatory regimes in Alberta and British Columbia. The AER released Bulletin 2016-16 which, among other things, implements important changes to the AER's procedures relating to liability management ratings, licence eligibility and licence transfers. In addition, changes with respect to licence eligibility were codified in amendments to AER *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("Directive 067").* Among other things, *Directive 067* provides the AER with broad discretion to determine if a party poses an "unreasonable risk" such that it should not be eligible to hold AER licences. The Government of British Columbia has announced similar policies and the British Columbia Oil and Gas Commission is exploring the development of a comprehensive liability management strategy, driven in part by the proliferation of orphan assets. The imposition of timelines for inactive sites is among the measures under consideration. These changes may impact Cenovus's ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions.

The aggregate value of the A&R liabilities assumed by the OWA has increased in recent years following the lower court decisions in Redwater and as a result of the current economic environment. To the extent the Supreme Court of Canada's decision in Redwater makes the transfer of oil and gas assets from insolvent parties more challenging because a trustee in bankruptcy is unable to separate economic assets from uneconomic assets within the insolvent party's estate in order to facilitate a sale process, the result could be additional assets being placed upon the OWA.

While the Supreme Court of Canada's decision in Redwater may reduce the A&R liabilities assumed by the OWA in the long-term, the OWA's A&R liabilities will remain at elevated levels until a significant number of orphaned wells are decommissioned by the OWA. As a result, the OWA may seek additional funding for such liabilities from industry participants, including Cenovus through an increase in its annual levy, further changes to regulations or other means. While the impact on Cenovus of any legislative, regulatory or policy decisions cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty regimes. The governments of Alberta and British Columbia receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights. Government regulation of Crown royalties is subject to change for a number of reasons, including, among other things, political factors. Royalties are typically calculated based on benchmark prices, productivity per well, location, date of discovery, recovery method, well depth and the nature and quality of petroleum product produced. There is also a mineral tax in each province levied on hydrocarbon production from lands in which the Crown does not own the mineral rights. The potential for changes in the royalty and mineral tax regimes applicable in the provinces in which Cenovus operates creates uncertainty relating to the ability to accurately estimate future Crown burdens and could have a significant impact on our business, financial condition, results of operations and cash flows.

The Government of Alberta has implemented a new Royalty Regime, Alberta's Modernized Royalty Framework ("MRF") which applies to all conventional wells spud on or after January 1, 2017. The MRF does not apply to oil sands production, which has its own separate royalty framework. Wells spud prior to July 13, 2016 will continue to operate under the previous royalty framework. Wells spud between July 13, 2016 and January 1, 2017 may elect to opt-in to the MRF if certain criteria are met. After December 31, 2026, all wells will be subject to the MRF. As part of the MRF, the Government of Alberta announced two new strategic royalty programs to encourage oil and gas producers to boost production and explore resources in new areas: the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program. These programs will take into account the higher costs associated with development of emerging resources and enhanced recovery methods when calculating royalty rates. The royalty structure and rates for oil sands production in Alberta remain generally unchanged following the royalty review. The Government of Alberta has indicated that it plans to modernize the process of calculating costs and collecting oil sands royalties, and has recently implemented public disclosure of cost, revenue and collection information relating to oil sands projects and royalties.

Further changes to any of the royalty regimes in Alberta, changes to the existing royalty regimes in British Columbia, changes to how existing royalty regimes are interpreted and applied by the applicable governments, or an increase in disclosure obligations for Cenovus could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates in Alberta or British Columbia would reduce our earnings and could make, in the respective province, future capital expenditures or existing operations uneconomic. A material increase in royalties or mineral taxes may reduce the value of our associated assets.

Environmental Regulatory Risk

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian and U.S. federal, provincial, territorial, state and municipal laws and regulations (collectively, the "environmental regulations"). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, costs, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances in the environment. They also impose restrictions, liabilities and obligations in connection with the management of water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The complexities of changes in environmental regulations make it difficult to predict the potential future impact to Cenovus.

Compliance with environmental regulations requires significant expenditures. Our future capital expenditures and operating expenses could continue to increase as a result of, among other things, developments in our business, operations, plans and objectives and changes to existing, or implementation of new, environmental regulations. Failure to comply with environmental regulations may result in, among other things, the imposition of fines, penalties, environmental protection orders, suspension of operations, and could adversely effect our reputation. The costs of complying with environmental regulations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase compliance costs, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Climate Change Regulation

Various federal, provincial and state governments have announced intentions to regulate GHG emissions. Some of these regulations are in effect while others remain in various phases of review, discussion or implementation in the U.S. and Canada.

In 2016, the Government of Canada ratified the international Paris Agreement on climate change and announced a new national carbon pricing regime (the "Carbon Strategy"). In 2018, the federal government finalized the *Greenhouse Gas Pollution Pricing Act* under the Carbon Strategy, which specifies (i) a carbon price on fossil fuels of \$20 per tonne of carbon dioxide equivalent ("CO2e") in 2019, rising by \$10 per year to \$50 per tonne CO2e in 2022 and (ii) an Output-Based Pricing System ("OBPS") for industrial facilities with annual emissions of 50 kilotonnes of GHG per year or more. OBPS facilities will be subject to the carbon price on the portion of emissions that exceed an annual output-based emissions limit, which can be satisfied by paying a charge, applying federally issued surplus credits or eligible offset credits. The federal carbon pricing system will apply only in jurisdictions that do not have equivalent measures in place.

The Alberta Climate Leadership Plan, sets forth several commitments relevant to the oil and gas sector: (1) the implementation of an economy-wide carbon levy; (2) limiting of oil sands emissions to a province-wide total of 100 megatonnes per year (compared to current industry emissions levels of approximately 70 megatonnes per year), with certain exceptions for cogeneration power sources and new upgrading capacity; and (3) a goal to reduce methane emissions from oil and gas activities by 45 percent by 2025. The economy-wide carbon levy is based on a rate of \$30 per tonne for 2018 and exempts activities integral to oil and gas production processes until 2023.

The *Alberta Carbon Competitiveness Incentive Regulation* ("CCIR", effective January 1, 2018) applies to facilities that emit greater than 100,000 tonnes of GHG per year. Facilities are exempt from the carbon levy, but are required to meet an emissions intensity benchmark which is set based on industry performance. Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. The benchmarks are subject to future adjustment.

The British Columbia *Carbon Tax Act* sets a carbon price of \$30 per tonne of CO2e on fuel combustion. Beginning April 1, 2018, the provincial carbon tax is expected to increase by \$5 per tonne of CO2e per year, reaching the federal target carbon price of $50 on April 1, 2021. The tax may also be expanded to fugitive and vented emissions from the oil and gas sector. The Government of British Columbia has also introduced measures to reduce upstream methane emissions by 45 percent and establish separate sector-level benchmarks to reduce carbon tax costs for industrial facilities.

In 2018, the federal government finalized regulations to limit the release of methane and volatile organic compounds with staged implementation over the 2020 to 2023 time period. Provinces may establish their own methane reduction regulations and set up equivalency agreements with the federal government. Alberta and British Columbia have developed methane reduction rules that are expected to align with the federal government's proposed regulations.

It is expected that the carbon pricing systems in Alberta and British Columbia will meet the requirements of the federal *Greenhouse Gas Pollution Pricing Act*. Our operating oil sands assets and two of our natural gas processing facilities are subject to the CCIR and are therefore exempt from the Alberta carbon levy. The carbon levy exemption for activities integral to oil and gas production processes applies to the vast majority of emissions related to activities in our Deep Basin assets. In 2023, when the current exemptions are expected to end, we expect that our conventional oil and gas production facilities will be eligible to opt-in to the CCIR thereby mitigating a portion of the cost associated with the carbon levy.

Uncertainties exist relating to the timing and effects of these emerging regulations, other contemplated legislation, including how they may be harmonized, making it difficult to accurately determine the cost impacts and effects on our suppliers. Additional changes to climate change legislation may adversely affect our business, financial condition, results of operations and cash flows, which cannot be reliably or accurately estimated at this time.

Other possible effects from emerging regulations may also include, but are not limited to: increased compliance costs; permitting delays; substantial costs to generate or purchase emission credits or allowances, all of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be available on an economic basis, required emission reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to such resources or technology to meet such emission reduction requirements or other compliance mechanisms may have a material adverse effect on our business resulting in, among other things, fines, permitting delays, penalties and the suspension of operations.

The extent and magnitude of any adverse impacts of current or additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time, in part because specific legislative and regulatory requirements have not been finalized and uncertainty exists with respect to the additional measures being considered and the time frames for compliance. Consequently, no assurances can be given that the effect of future climate change regulations will not be significant to Cenovus. There is also risk that we could face claims initiated by third parties relating to climate change or other environmental regulations. These claims could, among other things, result in litigation targeted against Cenovus and the oil and gas industry generally, and should any such litigation claims arise, they may have a material adverse effect on our business.

Low Carbon Fuel Standards

Existing and proposed environmental legislation and regulation developed by certain U.S. states, Canadian provinces, the Canadian federal government and members of the European Union, regulating carbon fuel standards could result in increased costs and reduced revenue. The potential regulation may negatively affect the marketing of Cenovus's bitumen, crude oil or refined products, and may require us to purchase emissions credits in order to affect sales in such jurisdictions.

Environment and Climate Change Canada has published a regulatory framework on its proposed clean fuel standard regulation to be adopted under the *Canadian Environmental Protection Act, 1999*. The clean fuel standard regulation will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. The stated purpose of the clean fuel standard is to incent the use of a broad range of low carbon fuels, energy sources and technologies. The clean fuel standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

The states of California and Oregon, and the province of British Columbia have implemented the Low Carbon Fuel Standard, the Clean Fuels Program, and the Renewable and Low Carbon Fuel Requirements Regulation, respectively. The regulations require the reduction of life cycle carbon emissions from transportation fuels. As an oil sands producer, we are not directly regulated and are not expected to have a compliance obligation. Refiners, importers, and fuel distributors in these jurisdictions are required to comply with the legislation.

Renewable Fuel Standards

Our U.S. refining operations are subject to various laws and regulations that impose stringent and costly requirements. Of specific note is the *Energy Independence and Security Act of 2007* ("EISA 2007") that established energy management goals and requirements. Pursuant to EISA 2007, among other things, the Environmental Protection Agency issued the Renewable Fuel Standard program that mandates the total volume of renewable transportation fuel sold or introduced in the U.S. and requires renewable fuels such as ethanol and advanced biofuels to be blended with gasoline by the obligated party. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. To the extent refineries do not blend renewable fuels into their finished products, they must purchase credits, referred to as RINs, in the open market. A RIN is a number assigned to each gallon of renewable fuel produced or imported into the U.S. RIN numbers were implemented to provide refiners with flexibility in complying with the renewable fuel standards.

Our refineries do not blend renewable fuels into the motor fuel products they produce and, consequently, we are obligated, through WRB, to purchase RINs in the open market, where prices fluctuate. In the future, the regulations could change the volume of renewable fuels required to be blended with refined products, creating volatility in the price for RINs or an insufficient number of RINs being available in order to meet the requirements. Our financial condition, results of operations, and cash flows may be materially adversely impacted as a result.

Marine Fuel Oil Sulphur Specification

As a specialized agency of the United Nations and the main regulatory body for the shipping industry, the International Maritime Organization ("IMO") is the global standard-setting authority for the safety, security and environmental performance of international shipping. IMO has set a global limit for sulphur in fuel oil used on board ships of 0.5 weight percent from January 1, 2020, drastically changed from the current upper limit of 3.5 weight percent. The IMO's goal is to significantly reduce the amount of sulphur oxide emanating from ships and it expects major health and environmental benefits for the world, particularly for populations living close to ports and coasts.

Refineries worldwide currently blend around three million barrels per day of high sulphur Residual Fuel Oil ("RFO") with lighter oil to make bunker fuel oil for the shipping industry. RFO is an outlet at the refinery for difficult to process crude components, usually high sulphur residuum. Sulphur reduction for RFO is more difficult than for lighter distillates as the asphaltene content in RFO requires more costly and complex processing.

Cenovus crude production contains a large amount of high sulphur residuum. Most of Cenovus's crude is processed by complex refineries. However, after 2020, the availability of complex refining capacity may become scarce. This coming IMO sulphur regulation has the potential to materially adversely impact our crude marketing and may materially contribute to increased widening of the light to heavy crude oil differential, distressing pricing for heavier crude oils including bitumen. The severity of the impact depends on the enforcement of the regulation, the ability of ship owners to install scrubbers, worldwide heavy sour crude production and additional heavy processing availability.

Species at Risk Act

The Canadian federal legislation, *Species at Risk Act,* and provincial counterparts regarding threatened or endangered species may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern, such as woodland caribou. Recent petitions and litigation against the federal government in relation to their obligations under the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, a suite of initiatives have been undertaken to support caribou recovery, including: a) the Alberta Caribou Action and Range Planning Project to develop long term habitat management plans such that ranges may return to self-sustaining status, b) development of methods for long term Regional Access Management Plans c) mineral development deferral agreements, and, d) negotiation of conservation agreements under Section 11 of the *Species at Risk Act*, which seek to codify concrete measures to support the conservation of the species and the protection of its critical habitat.

If plans and actions undertaken by the provinces are deemed not to provide sufficient likelihood of caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. For example, the federal government is undertaking an imminent threat assessment for a portion of caribou herd range in West Central Alberta which may compel further intervention (this range does not overlap Cenovus's lands or operations), a habitat protection order under Section 58 of the *Species at Risk Act* is pending for federally administered lands (including the Saskatchewan side of the Cold Lake Air Weapons Range to the east of Cenovus operations), and is the subject of an application for a protection order for the critical habitat of five sub-populations of woodland caribou. On January 24, 2019, the Athabasca Chipewyan and Mikisew Cree First Nations in northern Alberta, together with the Alberta Wilderness Association and the David Suzuki Foundation, filed an application for judicial review in federal court arguing that the Minister has failed to protect the habitat of five boreal woodland caribou herds. The applicants claim that although the Minister acknowledges that provincial recovery plans for the threatened species are inadequate, the federal government has not fulfilled its duty to issue a protective order under the *Species at Risk Act.*

Federal Air Quality Management System

The Multi-sector Air Pollutants Regulations ("MSAPR"), issued under the *Canadian Environmental Protection Act, 1999*, seek to protect the environment and health of Canadians by setting mandatory, nationally-consistent air pollutant emission standards. The MSAPR are aimed at equipment-specific Base-Level Industrial Emissions Requirements ("BLIERs"). Nitrogen oxide BLIERs from our non-utility boilers, heaters and reciprocating engines are regulated in accordance with specified performance standards. We do not anticipate a material impact to existing or future operations as a result of the MSAPR.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter ("PM2.5") and ozone were introduced as part of a national Air Quality Management System. Provincial level implementation of the CAAQS may occur at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where Cenovus operates that may result in adverse impacts such as but not limited to increased operating costs.

Federal Review of Environmental and Regulatory Processes

In 2016, the Government of Canada commenced a review of the environmental and regulatory processes administered under the *National Energy Board Act*, *Canadian Environmental Assessment Act*, *Fisheries Act*, and the *Navigation Protection Act*. In February 2018, the Government of Canada proposed amendments to the *Fisheries Act* and the *Navigation Protection Act*, and proposed the enactment of the *Impact Assessment Act*, and the *Canadian Energy Regulator Act*.

The proposed *Fisheries Act* amendments restore the previous prohibition against "harmful alteration, disruption or destruction of fish habitat" ("HADD") and introduce several new requirements to expand the act's scope of protection and role of Aboriginal groups and interests. The HADD requirement may result in increased permitting requirements where our operations potentially impact fish habitat.

The proposed changes to the *Navigation Protection Act*, including renaming the Act to the *Canadian Navigable Waters Act*, will expand the scope to all navigable waters, create greater oversight for navigable waters and, consistent with the *Fisheries Act*, introduces requirements to expand the Act's scope of protection and the role of Aboriginal groups and interests.

The proposed *Impact Assessment Act*, will replace the *Canadian Environmental Assessment Act* and, if passed, will establish the Impact Assessment Agency of Canada, which will lead and coordinate impact assessments for all designated projects, including those previously administered by the National Energy Board. The proposed legislation expands the assessment considerations beyond the environment to include health, economy, social, gender and impacts on Aboriginal peoples. The proposed *Canadian Energy Regulator Act* is intended to replace the National Energy Board with the Canadian Energy Regulator and modify the regulator's role.

The regulatory proposals are subject to change as they work through the Parliamentary process. The extent and magnitude of any adverse impacts resulting from these proposed legislative changes on project development and operations cannot be reliably or accurately estimated at this time as uncertainty exists with respect to their implementation and what the accompanying regulations, including the types of projects that will be assessed under the new legislation. Increased environmental assessment obligations and reporting obligations may create risk of increased costs and project development delays.

British Columbia Review of Environmental and Regulatory Processes

In 2018, the Government of British Columbia continued progressing their commitments to reviewing the province's environmental assessment process and other regulatory processes, including enacting an endangered species law and harmonizing other laws related to the environment. The *Environmental Assessment Act* was passed in the Fall of 2018 and allows wide discretionary powers to the Minister to designate a project for review on request from the public. The government has also implemented its commitment to proceed with a scientific review of hydraulic fracturing to determine impacts on water and the relationship to seismic activity for which the report will be released in 2019.

In January 2018, the Government of British Columbia proposed restrictions on the increase of diluted bitumen transportation as part of the second phase of regulations to improve preparedness, response and recovery from potential oil spills. In March of 2018, the Government of British Columbia submitted a court reference to the British Columbia Court of Appeal to confirm whether or not it is within their jurisdiction to regulate transportation of bitumen within the province, as set out in the proposed regulation. The court reference has not yet been heard.

The extent and magnitude of any adverse impacts of changes to the legislation or policies on project development and operations cannot be estimated at this time as uncertainty exists with respect to recommendations being considered or to be developed. Increased environmental assessment obligations or transportation restrictions may create risk of increased costs and project development delays.

Water Licences

In Alberta, we utilize fresh water in certain operations, which is obtained under licences issued pursuant to the *Water Act* to provide domestic and utility water at our SAGD facilities and for our bitumen delineation programs and our activities in the Deep Basin. Currently, we are not required to pay for the water we use under these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. If a change under these licences reduces the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial performance. There can be no assurance that the licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. In addition, the expansion of our projects rely on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted on terms favourable to us, or at all, or that such additional water will in fact be available to divert under such licences.

In British Columbia, groundwater use is regulated with the coming into force of the *Water Sustainability Act*. Most groundwater use (other than domestic use) requires a water licence to divert water from an aquifer. There is a three year period for existing non-domestic groundwater users to transition into the current water licensing scheme and its first-in-time, first-in-right priority system. There are annual water rental fees established by the regulations to the *Water Sustainability Act*. Additional supporting regulations continue to be proposed and brought into force.

Water use fees may increase and licence terms and conditions may be amended in the future, which may adversely affect our business including ability to operate. In addition, there is no assurance that if we require new licences or amendments to existing licences, that these licences or amendments will be granted on favourable terms.

Alberta Wetland Policy

Wetland management within Alberta is regulated by Section 36 of the *Water Act,* together with the Alberta Wetland Policy and the Provincial Wetland Restoration and Compensation Guide.

Pursuant to the Alberta Wetland Policy, developers of oil and gas assets in wetlands areas may be required to avoid the wetlands or mitigate the development's effects on wetlands.

The Alberta Wetland Policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, as projects approved prior to July 4, 2016 are exempted from the policy. However, new project developments and future phase expansions that have not yet been approved are expected to be subject to this policy. As our oil sands leases are in areas where wetlands cover over 50 percent of the landscape, avoidance of wetlands is not possible. In addition, Deep Basin development activities are subject to the policy if they occur in wetlands. In these cases we are required to comply with requirements for wetland reclamation or, where permanent wetland loss will occur, payment to an in-lieu fee program, or permittee-responsible replacement action.

Based on the *Alberta Wetland Mitigation Directive, 2018* and consultation with Alberta Environment and Parks as well as the AER, we do not anticipate a material impact of the policy on our oil sands or unconventional assets in the Deep Basin.

Hydraulic Fracturing

Certain stakeholders have made claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and suggest that additional federal, provincial, territorial and/or municipal laws and regulations may be needed to more closely regulate the hydraulic fracturing process.

The Canadian federal government and certain provincial governments continue to review certain aspects of the existing scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. Further, certain governments in jurisdictions where the Company does not currently operate have considered or implemented moratoriums on hydraulic fracturing until further studies can be completed and some governments have adopted, and others have considered adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations.

Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to limitations or restrictions to oil and gas development activities, operational delays, additional operating requirements, or increased third-party or governmental claims that could increase our cost of compliance and doing business as well as reduce the amount of natural gas and oil that Cenovus is ultimately able to produce from its reserves.

Seismic Activity

Some areas of British Columbia and Alberta are experiencing increasing localized frequency of seismic activity which has been associated with oil and gas operations. Although the occurrence of seismicity in relation to oil and gas operations is generally very low, it has been linked to deep disposal of wastewater in the U.S. and has been correlated with hydraulic fracturing in western Canada which has prompted legislative and regulatory initiatives intended to address these concerns.

These initiatives have the potential to require additional monitoring, restrict the injection of produced water in certain disposal wells and/or modify or curtail hydraulic fracturing operations which could lead to operational delays, increase compliance costs or otherwise adversely impact Cenovus's operations.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that cause negative public opinion have the potential to negatively impact our reputation which may adversely affect our share price, development plans and our ability to continue operations.

Public Perception of Alberta Oil Sands

Development of the Alberta oil sands has received considerable attention in recent public commentary on the subjects of environmental impact, climate change and GHG emissions. Despite that much of the focus is on bitumen mining operations and not in situ production, public concerns about oil sands generally and GHG emissions, water and land use practices and indigenous engagement in oil sands developments specifically may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertainty in economic modeling of current and future projects and delays relating to the sanctioning of future projects.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Other Risks

Risks Related to the Acquisition

Unexpected Costs or Liabilities Related to the Acquisition

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

In connection with the Acquisition, there may be liabilities that we failed to discover or were unable to quantify in our due diligence conducted prior to the execution of the purchase and sale agreement between ConocoPhillips and Cenovus dated March 29, 2017, as amended (the "Acquisition Agreement"), and we may not be indemnified for some or all of these liabilities. The discovery or quantification of any material liabilities could have a material adverse effect on our business, financial condition or future prospects. In addition, the Acquisition Agreement limits the amount for which we are indemnified, such that liabilities in respect of the Acquisition may be greater than the amounts for which we are indemnified under the Acquisition Agreement.

Realization of Acquisition Benefits

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

Amount of Contingent Payments

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

Effect on Market Price from Future Sales of common shares of Cenovus by ConocoPhillips

The future sales of common shares of Cenovus into the market held by ConocoPhillips, either through open market trades on the Toronto and New York stock exchanges, through privately arranged block trades, or pursuant to prospectus offerings made in accordance with the registration rights agreement, could adversely affect prevailing market prices for the common shares. In addition, market perception regarding ConocoPhillips' intention to make sales of Cenovus common shares may have a negative impact on the trading price of these common shares.

Tax Laws

Income tax laws, other laws or government incentive programs may in the future be changed or interpreted in a manner that adversely affects Cenovus and its shareholders. Tax authorities having jurisdiction over Cenovus may disagree with the manner in which we calculate our tax liabilities such that its provision for income taxes may not be sufficient, or such authorities could change their administrative practices to Cenovus's detriment or the detriment of its shareholders. In addition, all of our tax filings are subject to audit by tax authorities who may disagree with such filings in a manner that adversely affects Cenovus and its shareholders.

United States Tax Risk

In the U.S., the *Tax Cuts and Jobs Act* was signed into law on December 22, 2017. The legislation reduces the federal corporate tax rate from 35 percent to 21 percent; allows immediate expensing of qualified property acquired prior to 2023; imposes a limitation on the utilization of post-2017 net operating losses to 80 percent of taxable income; revises the previous limitation on the deductibility of interest expense; and introduces new provisions imposing a minimum tax in certain circumstances when a company has payments to a related foreign entity. There are significant gaps in the legislation that will be filled through Treasury regulations. While Treasury has released a number of proposed regulations as of December 31, 2018, there is a possibility that public input during the regulatory comment period may cause Treasury to change its interpretation of certain provisions when the regulations are finalized. Negative consequences may arise as a result of continued developments associated with this legislation and accompanying regulations.

Arrangement Related Risk

We have certain post-Arrangement indemnification and other obligations under each of the arrangement agreement (the "Arrangement Agreement") and the separation and transition agreement (the "Separation Agreement"), both of which are among Encana Corporation ("Encana"), 7050372 Canada Inc. and Cenovus Energy Inc. (formerly, Encana Finance Ltd.), dated October 20, 2009 and November 30, 2009 respectively, entered in connection with the Arrangement. Encana and Cenovus have agreed to indemnify each other for certain liabilities and obligations associated with, among other things, in the case of Encana's indemnity, the business and assets retained by Encana, and in the case of Cenovus's indemnity, the Cenovus business and assets. At the present time, we cannot determine whether we will have to indemnify Encana for any substantial obligations under the terms of the Arrangement. We also cannot assure that if Encana has to indemnify us and our affiliates for any substantial obligations, Encana will be able to satisfy such obligations.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operation and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR at sedar.com, on EDGAR at sec.gov and cenovus.com.

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 Consolidated Financial Statements.

Joint Arrangements

The classification of a joint arrangement as either a joint operation or a joint venture requires judgment. Cenovus holds a 50 percent interest in WRB, a jointly controlled entity. It was determined that Cenovus has the rights to the assets and obligations for the liabilities of WRB. As a result, the joint arrangement is classified as a joint operation and the Company's share of the assets, liabilities, revenues and expenses are recorded in the Consolidated Financial Statements.

Prior to May 17, 2017, Cenovus held a 50 percent interest in FCCL, which was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition, Cenovus controls FCCL, as defined under IFRS 10, and, accordingly, FCCL has been consolidated.

In determining the classification of our joint arrangements under IFRS 11, we considered the following:

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.

- FCCL operated like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

The application of Cenovus's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Identification of CGUs

CGUs are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and reversals.

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. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period. Changes to these assumptions and key sources of estimation could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Deep Basin segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by our IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For our upstream assets, these estimates include forward commodity prices, expected production volumes, quantity of reserves and resources, discount rates, future development and operating expenses, and income tax rates. Recoverable amounts for the refining assets and crude-by-rail terminal use assumptions such as throughput, forward commodity prices, operating expenses, transportation capacity, supply and demand conditions, and income tax rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets. Refer to the Reportable Segments section of this MD&A for more details on impairments and reversals.

As at December 31, 2018, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs. Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2018 by our IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2018, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2019	2020	2021	2022	2023	Average Annual Increase Thereafter (percent)
WTI (US$/barrel)	58.58	64.60	68.20	71.00	72.81	2.0
WCS (C$/barrel)	51.55	59.58	65.89	68.61	70.53	2.1
Edmonton C5+ (C$/barrel)	70.10	79.21	83.33	86.20	88.16	2.0
AECO (C$/Mcf) (1)	1.88	2.31	2.74	3.05	3.21	2.0

(1) Assumes gas heating value of one MMBtu per thousand cubic feet.

Discount and Inflation Rates

Discounted future cash flows are determined by applying a discount rate between 10 percent and 15 percent, based on the individual characteristics of the CGU and other economic and operating factors. Inflation is estimated at two percent, which is common industry practice and used by Cenovus's IQREs in preparing their reserves reports.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. Refer to Note 25 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

Onerous Contract Provisions

A contract is considered to be onerous when the unavoidable cost of meeting the obligations of the contract exceed the economic benefits expected to be derived from the contract. Determining when to record a provision for an onerous contract requires Management judgement and the use of estimates and assumptions, including the nature, extent and timing of future cash flows and discount rates related to the contract.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired and liabilities assumed in a business combination, including contingent consideration and goodwill, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparables and discounted cash flows which rely on assumptions such as forward prices, reserve and resources estimates, production costs, volatility, Canadian-U.S. foreign exchange rates and discount rates. Changes in these variables could significantly impact the carrying value of the net assets.

Income Tax Provisions

Tax regulations and legislation and the interpretations thereof in the various jurisdictions in which Cenovus operates are subject to change. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods. Refer to the Corporate and Eliminations section of this MD&A for more details on changes to estimates related to income taxes.

Changes in Accounting Policies

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

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

Further information about changes to our accounting policies resulting from the adoption of IFRS 9 and IFRS 15 can be found in Note 4 to the Consolidated Financial Statements.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2019 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2018. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates.

Leases

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

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

IFRS 16 is effective for years beginning on or after January 1, 2019 and may be applied retrospectively or using a modified retrospective approach. We have selected to use the modified retrospective approach which does not require restatement of prior period financial information as the cumulative effect of applying the standard to prior periods is recorded as an adjustment to opening retained earnings. On initial adoption, we have elected to use the following practical expedients permitted under the standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than 12 months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use ("ROU") asset if the underlying asset is of low dollar value;
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease; 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.

On adoption of IFRS 16, we will recognize lease liabilities in relation to leases under the principles of the new standard measured at the present value of the remaining lease payments, discounted using the interest rate implicit in the lease or our incremental borrowing rate as at January 1, 2019. The associated ROU assets will be 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.

Adoption of the new standard will result in the recognition of additional lease liabilities and ROU assets of approximately $1.5 billion and $0.9 billion, respectively. We have identified ROU assets and lease liabilities primarily related to office space, railcars, storage tanks, drilling rigs and other field equipment. The impact on the consolidated statement of earnings will be as follows:

- Lower general and administrative expenses, transportation and blending costs, operating costs, purchased product and property, plant and equipment expenditures;
- Higher finance expenses due to the interest recognized on the lease obligations; and
- Higher depreciation expense related to the ROU assets.

We have reviewed office space contracts where the Company is the lessor and as a result of these assessments will recognize a $16 million net investment from these leases on January 1, 2019.

Uncertain Tax Positions

In June 2017, the IASB issued International Financial Reporting Interpretation Committee ("IFRIC") 23, *"Uncertainty over Income Tax Treatments"*. 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. IFRIC 23 is effective for annual periods beginning on or after January 1, 2019 using either a modified or full retrospective approach. IFRIC 23 will not have a significant impact on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2018. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2018.

The Company previously limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures of the Deep Basin Assets, acquired by the Company through a business combination on May 17, 2017. During the second quarter of 2018, the Company completed the evaluation and integration of the controls, policies and procedures of the Deep Basin Assets. No material weaknesses or significant deficiencies were noted during the integration. There have been no changes during the year ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect ICFR.

The effectiveness of our ICFR was audited as at December 31, 2018 by PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, as stated in their Report of Independent Registered Public Accounting Firm, which is included in our audited Consolidated Financial Statements for the year ended December 31, 2018.

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.

CORPORATE RESPONSIBILITY

We are committed to operating in a responsible manner and integrating our corporate responsibility principles in the way we conduct our business. Our Corporate Responsibility ("CR") policy guides our activities in the areas of: Leadership, Corporate Governance and Business Practices, People, Environmental Performance, Stakeholder and Aboriginal Engagement, and Community Involvement and Investment.

We published our 2017 CR report in August 2018 to report on our management efforts and performance across the above noted areas within our CR policy, as well as other environment, social and governance topics that are important to our stakeholders. Our CR report also lists external recognition we received for our commitment to corporate responsibility, and is available on our website at cenovus.com.

OUTLOOK

In 2019 we expect to see continued commodity price volatility and market access constraints for heavy oil exiting Alberta. On December 2, 2018, the Government of Alberta announced a temporary mandatory oil production cut for Alberta producers to address the record-high light-heavy crude oil differentials impacting our industry. We had already begun voluntarily reducing production levels at our Foster Creek and Christina Lake facilities during the third and fourth quarters of 2018 in response to limited takeaway capacity and discounted heavy oil pricing, and continue to work with the AER to determine the impact that the mandatory production curtailment will have on Cenovus. While our production levels will be impacted due to the curtailment, the expected improvement to the oil price is anticipated to have a positive impact on our cash flows.

We 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. In 2018, we strengthened our long-term market access position by signing rail agreements to transport approximately 100,000 barrels per day of heavy crude oil to various destinations on the U.S. Gulf Coast, providing a means to move our volumes out of Alberta and to a customer base in other market centres, as well as mitigating some of the price impact of pipeline congestion on those barrels. We also recently increased our committed capacity on the proposed Keystone XL Pipeline by 100,000 barrels per day. We expect that transportation challenges faced by our industry will continue to negatively impact heavy oil prices, demonstrating the need for increased utilization of rail within the industry, and for approved pipeline projects in North America to proceed as soon as possible.

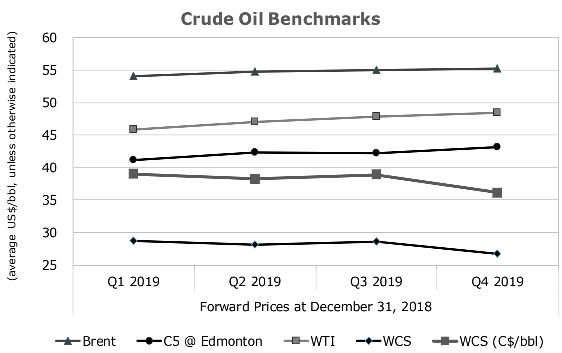
Through a continued focus on capital discipline and cost reductions, we have reduced the amount of capital needed to sustain our base business and expand our projects, which we believe will further help support our financial resilience.

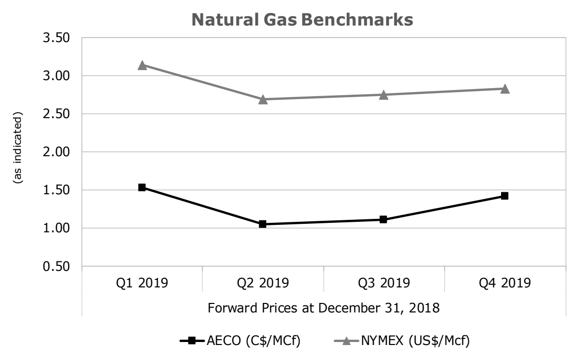
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

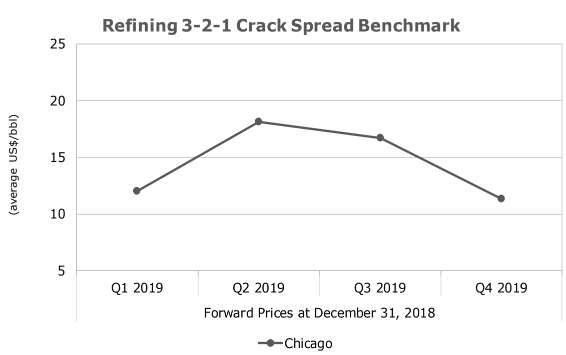
- We expect the general outlook for light crude oil prices to remain constructive and largely tied to the extent to which OPEC curtails production, as agreed to at their December 2018 meeting, the degree to which the U.S. enforces export sanctions on Iranian crude oil, and the degree to which global demand growth continues;
- Overall, crude oil price volatility is expected to decrease as inventories return to historical levels;
- We anticipate the Brent-WTI and the WTI-WTS differentials will narrow once additional pipeline capacity out of the Permian basin becomes available in the second half of 2019;
- Continuous OPEC cuts, enforcement of Iranian sanctions, and Venezuelan production declines will be supportive of the recent 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 mandatory temporary production curtailments in Alberta, the potential start-up of Enbridge Inc.'s Line 3 Replacement Project, 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 (IMO) 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.

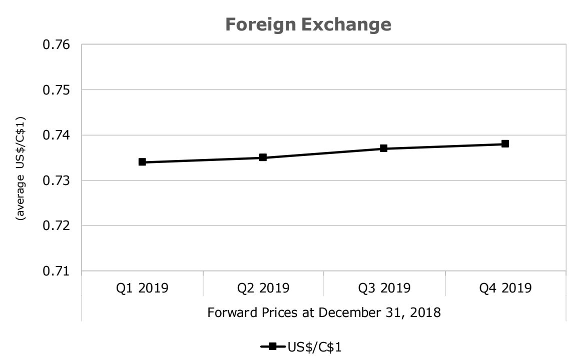




Natural gas prices are anticipated to remain challenged with North American supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain wide as increasing supply is anticipated to exceed the limits of existing 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 twice in 2017 and three times again in 2018, marking a notable shift for Canada towards a tighter monetary policy.





Our exposure to the light-heavy crude oil price differentials is composed of both a global light-heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of 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 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 high-return growth projects. Maintaining our financial resilience and flexibility while continuing to deliver safe and reliable operations remains a top priority.

In 2019, we anticipate capital investment to be between $1.2 billion and $1.4 billion. We plan to direct the majority of our 2019 capital budget towards sustaining oil sands production, while supporting the completion of the Christina Lake phase G expansion, which is ahead of schedule and expected to be completed in the second quarter of 2019. We have flexibility on when we start production from Christina Lake phase G, and will take into consideration whether mandated production curtailments have been lifted and 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 scheduled maintenance and reliability work at the Refineries.

As at December 31, 2018, our net debt position was $8.4 billion. Through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $5.3 billion of liquidity as at December 31, 2018.

Over the long-term, we continue to target a Net Debt to Adjusted EBIDTA 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. In 2018, we made significant progress in strengthening our long-term market access position through three-year strategic agreements with major rail companies to transport approximately 100,000 barrels per day of heavy crude oil from northern Alberta to various destinations on the U.S. Gulf Coast. We have already begun shipping under these contracts, and anticipate ramping up to 100,000 barrels per day through 2019. While we remain confident that new pipeline capacity will be constructed, these rail agreements will help get our oil to higher-price markets. 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.

In addition to our rail agreements, we recently increased our committed capacity on the proposed Keystone XL Pipeline. Between Keystone XL and the Trans Mountain Expansion Project, we now have 275,000 barrels per day of potential future pipeline capacity to the West Coast and U.S. Gulf Coast.

Cost Leadership

Over the past four years, we have achieved significant improvements in our operating and sustaining capital costs. We will 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 2018 guidance estimates; expected future production, including the timing, stability or growth thereof; the impact of the Alberta Government'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 judgements; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; achievement of expected impacts of the Acquisition; successful completion of the integration of the Deep Basin Assets; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and the timelines we expect; forecast 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 December 10, 2018, assumes: Brent prices of US$66.50/bbl, WTI prices of US$57.00/bbl; WCS of US$30.00/bbl; AECO natural gas prices of $1.75/GJ; Chicago 3-2-1 crack spread of US$16.50/bbl; and an exchange rate of $0.76 US$/C$.

The risk factors and uncertainties that could cause our actual results to differ materially, include: 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, 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 judgements; our ability to replace and expand oil and gas reserves; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of our assets or goodwill from time to time; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change 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 and regulatory actions against us.

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of our material risk factors, see “Risk Management and Risk Factors” in this MD&A for the period ended December 31, 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 Consolidated Financial Statements.

Total Production From Continuing Operations

Continuing Upstream Financial Results

Year Ended December 31, 2018 ($ millions)	Per Consolidated Financial Statements: Oil Sands[1]	Deep Basin[1]	Continuing Operations	Adjustments: Condensate	Inventory	Internal Usage[2]	Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	10,026	904	10,930	(4,993)	-	(179)	(69)	5,689
Royalties	473	72	545	-	-	-	-	545
Transportation and Blending	5,879	90	5,969	(4,993)	-	-	(4)	972
Operating	1,037	403	1,440	-	-	(179)	(37)	1,224
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	2,637	338	2,975	-	-	-	(28)	2,947
(Gain) Loss on Risk Management	1,551	26	1,577	-	-	-	-	1,577
Operating Margin	1,086	312	1,398	-	-	-	(28)	1,370

Year Ended December 31, 2017 ($ millions)	Per Consolidated Financial Statements: Oil Sands[1]	Deep Basin[1]	Continuing Operations	Adjustments: Condensate	Inventory	Internal Usage[2]	Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	7,362	555	7,917	(3,050)	-	-	(45)	4,822
Royalties	230	41	271	-	-	-	-	271
Transportation and Blending	3,704	56	3,760	(3,050)	-	-	(1)	709
Operating	934	250	1,184	-	-	-	(77)	1,107
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	2,494	207	2,701	-	-	-	33	2,734
(Gain) Loss on Risk Management	307	-	307	-	-	-	-	307
Operating Margin	2,187	207	2,394	-	-	-	33	2,427

Year Ended December 31, 2016 ($ millions)	Per Consolidated Financial Statements: Oil Sands[1]	Deep Basin[1]	Continuing Operations	Adjustments: Condensate	Inventory	Internal Usage[2]	Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	2,929	-	2,929	(1,402)	-	-	(2)	1,525
Royalties	9	-	9	-	-	-	-	9
Transportation and Blending	1,721	-	1,721	(1,402)	44	-	-	363
Operating	501	-	501	-	-	-	(4)	497
Production and Mineral Taxes	-	-	-	-	-	-	-	-
Netback	698	-	698	-	(44)	-	2	656
(Gain) Loss on Risk Management	(179)	-	(179)	-	-	-	-	(179)
Operating Margin	877	-	877	-	(44)	-	2	835

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

Three Months Ended December 31, 2018 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands[3]	Deep Basin[3]	Continuing Operations	Adjustments: Condensate	Inventory	Internal Usage[4]	Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	1,380	190	1,570	(1,026)	-	(48)	(20)	476
Royalties	(39)	10	(29)	-	-	-	-	(29)
Transportation and Blending	1,263	18	1,281	(1,026)	-	-	-	255
Operating	248	100	348	-	-	(48)	(9)	291
Production and Mineral Taxes	-	-	-	-	-	-	-	-
Netback	(92)	62	(30)	-	-	-	(11)	(41)
(Gain) Loss on Risk Management	86	-	86	-	-	-	-	86
Operating Margin	(178)	62	(116)	-	-	-	(11)	(127)

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

Three Months Ended December 31, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments				Basis of Netback Calculation
	Oil Sands[1]	Deep Basin[1]	Continuing Operations	Condensate	Inventory	Internal Usage[2]	Other	Continuing Operations
Gross Sales	2,424	231	2,655	(990)	-	-	(15)	1,650
Royalties	113	20	133	-	-	-	-	133
Transportation and Blending	1,193	24	1,217	(990)	(1)	-	2	228
Operating	271	94	365	-	-	-	(15)	350
Production and Mineral Taxes	-	1	1	-	-	-	-	1
Netback	847	92	939	-	1	-	(2)	938
(Gain) Loss on Risk Management	235	-	235	-	-	-	-	235
Operating Margin	612	92	704	-	1	-	(2)	703

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

Oil Sands

Year Ended December 31, 2018 ($ millions)	Basis of Netback Calculation			Adjustments				Per Consolidated Financial Statements[3]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	2,531	2,489	5,020	1	4,993	-	12	10,026
Royalties	371	102	473	-	-	-	-	473
Transportation and Blending	495	391	886	-	4,993	-	-	5,879
Operating	532	492	1,024	2	-	-	11	1,037
Netback	1,133	1,504	2,637	(1)	-	-	1	2,637
(Gain) Loss on Risk Management	683	868	1,551	-	-	-	-	1,551
Operating Margin	450	636	1,086	(1)	-	-	1	1,086

Year Ended December 31, 2017 ($ millions)	Basis of Netback Calculation			Adjustments				Per Consolidated Financial Statements[3]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	1,945	2,345	4,290	8	3,050	-	14	7,362
Royalties	178	52	230	-	-	-	-	230
Transportation and Blending	387	266	653	-	3,050	-	1	3,704
Operating	465	403	868	9	-	-	57	934
Netback	915	1,624	2,539	(1)	-	-	(44)	2,494
(Gain) Loss on Risk Management	131	176	307	-	-	-	-	307
Operating Margin	784	1,448	2,232	(1)	-	-	(44)	2,187

Year Ended December 31, 2016 ($ millions)	Basis of Netback Calculation			Adjustments				Per Consolidated Financial Statements[3]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	773	736	1,509	16	1,402	-	2	2,929
Royalties	-	9	9	-	-	-	-	9
Transportation and Blending	225	137	362	1	1,402	(44)	-	1,721
Operating	269	217	486	11	-	-	4	501
Netback	279	373	652	4	-	44	(2)	698
(Gain) Loss on Risk Management	(90)	(89)	(179)	-	-	-	-	(179)
Operating Margin	369	462	831	4	-	44	(2)	877

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

Three Months Ended December 31, 2018 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments Condensate	Inventory	Other	Per Interim Consolidated Financial Statements(1) Total Oil Sands
Gross Sales	265	84	349	-	1,026	-	5	1,380
Royalties	(5)	(34)	(39)	-	-	-	-	(39)
Transportation and Blending	141	96	237	-	1,026	-	-	1,263
Operating	123	121	244	1	-	-	3	248
Netback	6	(99)	(93)	(1)	-	-	2	(92)
(Gain) Loss on Risk Management	45	41	86	-	-	-	-	86
Operating Margin	(39)	(140)	(179)	(1)	-	-	2	(178)

Three Months Ended December 31, 2017 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments Condensate	Inventory	Other	Per Interim Consolidated Financial Statements(1) Total Oil Sands
Gross Sales	626	804	1,430	1	990	-	3	2,424
Royalties	91	22	113	-	-	-	-	113
Transportation and Blending	106	96	202	-	990	1	-	1,193
Operating	137	123	260	3	-	-	8	271
Netback	292	563	855	(2)	-	(1)	(5)	847
(Gain) Loss on Risk Management	98	137	235	-	-	-	-	235
Operating Margin	194	426	620	(2)	-	(1)	(5)	612

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

Deep Basin

Year Ended December 31, 2018 ($ millions)	Basis of Netback Calculation Total	Adjustments Other(3)	Per Consolidated Financial Statements(2) Total Deep Basin
Gross Sales	847	57	904
Royalties	72	-	72
Transportation and Blending	86	4	90
Operating	377	26	403
Production and Mineral Taxes	1	-	1
Netback	311	27	338
(Gain) Loss on Risk Management	26	-	26
Operating Margin	285	27	312

Year Ended December 31, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other(3)	Per Consolidated Financial Statements(2) Total Deep Basin
Gross Sales	524	31	555
Royalties	41	-	41
Transportation and Blending	56	-	56
Operating	230	20	250
Production and Mineral Taxes	1	-	1
Netback	196	11	207
(Gain) Loss on Risk Management	-	-	-
Operating Margin	196	11	207

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

Three Months Ended December 31, 2018 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[2]	Per Interim Consolidated Financial Statements[1] Total Deep Basin
Gross Sales	175	15	190
Royalties	10	-	10
Transportation and Blending	18	-	18
Operating	94	6	100
Production and Mineral Taxes	-	-	-
Netback	53	9	62
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	9	62

Three Months Ended December 31, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[2]	Per Interim Consolidated Financial Statements[1] Total Deep Basin
Gross Sales	219	12	231
Royalties	20	-	20
Transportation and Blending	26	(2)	24
Operating	87	7	94
Production and Mineral Taxes	1	-	1
Netback	85	7	92
(Gain) Loss on Risk Management	-	-	-
Operating Margin	85	7	92

(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 December 31, 2018	 December 31, 2017	Year Ended December 31 2018	 2017	 2016
Oil Sands					
Foster Creek	143,928	143,586	162,685	121,806	69,647
Christina Lake	186,530	193,734	204,016	161,514	79,481
Total Oil Sands Crude Oil	330,458	337,320	366,701	283,320	149,128
Natural Gas (MMcf per day)	-	7	1	10	17
Total Oil Sands (BOE per day)	330,458	338,524	366,905	284,984	151,961
Deep Basin					
Total Liquids	28,111	33,147	32,454	20,850	-
Natural Gas (MMcf per day)	469	509	527	316	-
Total Deep Basin (BOE per day)	106,232	117,931	120,258	73,492	-
Less: Internal Consumption [3] (MMcf per day)	(310)	-	(306)	-	-
Sales From Continuing Operations [3] (BOE per day)	385,023	456,455	436,163	358,476	151,962

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