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

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 11, 2020, should be read in conjunction with our December 31, 2019 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 11, 2020, 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 11, 2020. 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. We adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section of this MD&A for further information.

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, 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 and Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil and natural gas company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2019, we had an enterprise value of approximately $24 billion. Operations include oil sands projects in northeast Alberta and established crude oil, natural gas liquids ("NGLs") and natural gas production in Alberta and British Columbia. Total production from our upstream assets averaged approximately 452,000 BOE per day in 2019. We also conduct marketing activities and have ownership interest in refining operations in the United States ("U.S."). The refineries processed an average of 443,000 gross barrels per day of crude oil feedstock into an average of 466,000 gross barrels per day of refined products in 2019.

Our Strategy

Our strategy is focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. Our business plan through 2024 will focus on sustainably growing shareholder returns and further reducing Net Debt as well as continuing to integrate Environmental, Social and Governance ("ESG") considerations into our business plan. 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.

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 are focused 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 are committed to 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 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

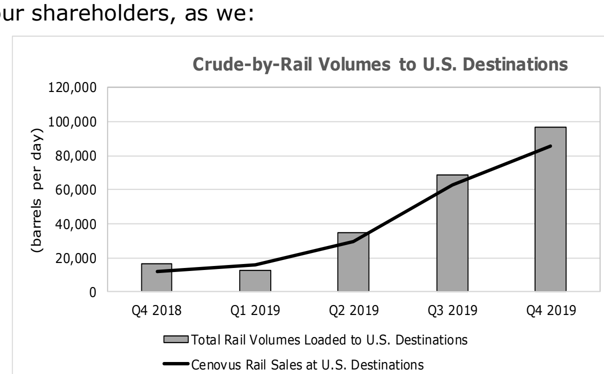
We strive to maintain an engaging workplace where people can grow their skills and capabilities to adapt to an ever-changing environment while delivering results for the business. We are focused on upholding trust in the communities where we operate by living up to our values and commitments.

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

YEAR IN REVIEW

In 2019, we delivered on the commitments we made to our shareholders, as we:

- Progressed our deleveraging plans by repaying US$1.8 billion of our unsecured notes and reducing Net Debt to $6.5 billion;
- Improved our long-term market access position through incremental pipeline capacity, strategic rail agreements and securing additional storage in the U.S. Gulf Coast ("USGC") to support the ramp up of our crude-by-rail activity;
- Ramped up our crude-by-rail activity by loading 53,345 barrels per day for delivery to U.S. destinations. Of these volumes, we sold an average of 48,626 barrels per day. We exited the year with our December loaded volumes averaging 105,985 barrels per day and rail sales of 91,059 barrels per day;



- Invested $1,176 million of capital compared with $1,363 million in 2018, reflecting our continued focus on capital discipline;
- Focused on cost leadership reflected in our operating cost reductions in our upstream assets;
- Increased our fourth quarter dividend 25 percent to $0.0625 per share; and
- Achieved production of one billion barrels of oil using steam-assisted gravity drainage ("SAGD") technology.

Upstream operational performance was very good, with production averaging 451,680 BOE per day, limited by the Government of Alberta's industry-wide mandatory production curtailment program. Our refineries demonstrated good performance despite unplanned outages throughout the year, and the turnaround activities at both the Wood River and Borger refineries (the "Refineries") in the fourth quarter. Effective January 1, 2020, as a result of new maximum demonstrated rates in 2019, Wood River was re-rated to reflect higher crude oil processing capacity of 346,000 gross barrels per day (2019 – 333,000 gross barrels per day).

Crude oil prices continued to be volatile throughout the year. West Texas Intermediate ("WTI") benchmark crude price ranged from a high of US$66.30 per barrel to a low of US$46.54 per barrel and averaged 12 percent lower than in 2018. The differential between WTI and Western Canadian Select ("WCS") at Hardisty prices narrowed to an average of US$12.76 per barrel, a 52 percent decrease compared with 2018, supported by the Government of Alberta's mandatory production curtailment program. The increase in the benchmark WCS prices to US$44.27 per barrel (2018 – US$38.46 per barrel) and a decrease in the cost of condensate used for blending had a positive impact on our upstream financial results (operating margin).

With market access constraints for Canadian crude oil production continuing, we have progressed on our strategy to maintain firm transportation through a combination of pipelines, rail and marine access. In 2019, we acquired additional pipeline and rail storage capacity allowing us to transport over 25 percent of our Oil Sands production to be sold at U.S. destinations which contributed to our increased realized price. We exited the year with 187,645 barrels per day of our Oil Sands production sold at U.S. destinations.

We achieved upstream operating margin from continuing operations of $3,723 million compared with $1,398 million in 2018, due to an increase in our average realized crude oil sales price and realized risk management losses of $23 million compared with $1,577 million in 2018.

Our Refining and Marketing segment generated operating margin of $737 million, down from 2018. While market crack spreads were relatively unchanged year-over-year, realized crack spreads were down due to the narrowing medium sour and heavy crude oil differentials, which resulted in lower crude advantage, partially offset by higher margins on fixed priced products associated with a lower benchmark WTI, and a reduction in the cost of Renewable Identification Numbers ("RINs").

In 2019, we:

- Increased our average realized crude oil sales price to $53.95 per barrel from $37.97 per barrel in 2018;
- Achieved Cash from Operating Activities of $3,285 million (2018 – $2,154 million), Adjusted Funds Flow of $3,724 million (2018 – $1,674 million), and Free Funds Flow of $2,548 million (2018 – $311 million); and
- Recorded Net Earnings from continuing operations of $2,194 million compared with a Net Loss from continuing operations of $2,916 million in 2018.

In the fourth quarter of 2019, the Government of Alberta announced a Special Production Allowance ("SPA") to provide curtailment relief equivalent to incremental increases in rail shipment and no curtailments on new conventional oil wells drilled to encourage more capital investment. Our production levels in 2020 are anticipated to be higher than in 2019 due to the SPA.

OPERATING AND FINANCIAL RESULTS

Selected Operating Results

	2019	Percent Change	2018	Percent Change	2017
Upstream Production Volumes					
Oil Sands (barrels per day)					
Foster Creek	**159,598**	**(1)**	161,979	30	124,752
Christina Lake	**194,659**	**(3)**	201,017	20	167,727
	354,257	**(2)**	362,996	24	292,479
Deep Basin (BOE per day)	**97,423**	**(19)**	120,258	64	73,492
Total Production from Continuing Operations [1] (BOE per day)	**451,680**	**(7)**	483,458	32	367,635
Production From Discontinued Operations (Conventional) (BOE per day)	**-**	**(100)**	294	(100)	102,855
Sales from Continuing Operations [2] (BOE per day)	**390,813**	**(10)**	436,163	22	358,476
Oil and Gas Reserves (MMBOE)					
Proved	**5,103**	**(1)**	5,167	(1)	5,232
Probable	**1,768**	**(3)**	1,821	(5)	1,910
Proved plus Probable	**6,871**	**(2)**	6,988	(2)	7,142
Refining and Marketing					
Crude Oil Runs [3] (Mbbls/d)	**443**	**(1)**	446	1	442
Refined Product [3] (Mbbls/d)	**466**	**(1)**	470	-	470
Crude Utilization [3] (percent)	**92**	**(5)**	97	1	96
Crude-by-Rail (barrels per day)					
Crude-by-Rail Loads [4]	**53,345**	**1,197**	4,113	-	-
Crude-by-Rail Sales [5]	**48,626**	**1,367**	3,314	-	-

(1) Includes natural gas volumes used for internal consumption by the Oil Sands segment of 320 MMcf per day for the year ended December 31, 2019 (306 MMcf per day in 2018 and no internal usage of Deep Basin production in 2017).
(2) Excludes natural gas volumes used for internal consumption by the Oil Sands segment of 320 MMcf per day for the year ended December 31, 2019 (306 MMcf per day in 2018 and no internal usage of Deep Basin production in 2017).
(3) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.
(4) Represents volumes transported outside of Alberta.
(5) Represents volumes sold outside of Alberta.

Upstream Production Volumes

Our upstream operations performed very well in 2019. Oil Sands production was 354,257 barrels per day (2018 – 362,996 barrels per day) due to mandatory production curtailments set by the Government of Alberta.

Deep Basin production in 2019 decreased to 97,423 BOE per day compared with 120,258 BOE per day in 2018 due to natural declines from lower sustaining capital investment, the divestiture of Cenovus Pipestone Partnership ("CPP") on September 6, 2018, and temporary well shut-ins resulting from low natural gas prices.

Oil and Gas Reserves

Based on our reserves reports prepared by independent qualified reserves evaluators ("IQREs"), at the end of 2019 we had total proved reserves and total proved plus probable reserves of approximately 5.1 billion BOE and 6.9 billion BOE, respectively, decreases of one percent and two percent compared with 2018.

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

Refining and Marketing

Crude oil runs and refined product output in 2019 were consistent with 2018. Operational performance was impacted by planned maintenance, unplanned outages, including a fire in a crude unit at Wood River, and planned turnaround activities at the Refineries. In the first quarter of 2018, both Refineries completed major planned turnarounds.

Further information on the changes in our financial and operating 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.

Selected Consolidated Financial Results

($ millions, except per share amounts)	2019	Percent Change	2018 (1)	Percent Change	2017 (1)
Operating Margin from Continuing Operations (2)	**4,460**	**86**	2,394	(20)	2,992
Cash From Operating Activities					
From Continuing Operations	**3,285**	**55**	2,118	(19)	2,611
Total	**3,285**	**53**	2,154	(30)	3,059
Adjusted Funds Flow (3)	**3,724**	**122**	1,674	(43)	2,914
Operating Earnings (loss) from Continuing Operations (3)	**456**	**117**	(2,755)	(8,003)	(34)
Per Share ($) (4)	**0.37**	**117**	(2.24)	(7,367)	(0.03)
Net Earnings (Loss)					
From Continuing Operations	**2,194**	**175**	(2,916)	(229)	2,268
Per Share ($) (4)	**1.78**	**175**	(2.37)	(215)	2.06
Total	**2,194**	**182**	(2,669)	(179)	3,366
Per Share ($) (4)	**1.78**	**182**	(2.17)	(171)	3.05
Total Assets	**35,713**	**2**	35,174	(14)	40,933
Total Long-Term Financial Liabilities (5)	**8,483**	**(1)**	8,602	(11)	9,717
Capital Investment (6)	**1,176**	**(14)**	1,363	(18)	1,661
Dividends					
Cash Dividends	**260**	**6**	245	9	225
Per Share ($)	**0.2125**	**6**	0.2000	-	0.2000

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and defined in this MD&A.
(3) Non-GAAP measure defined in this MD&A.
(4) Represented on a basic and diluted per share basis.
(5) Includes Long-Term Debt, Lease Liabilities, Risk Management, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(6) Includes expenditures on property, plant and equipment ("PP&E"), Exploration and Evaluation ("E&E") assets and assets held for sale.

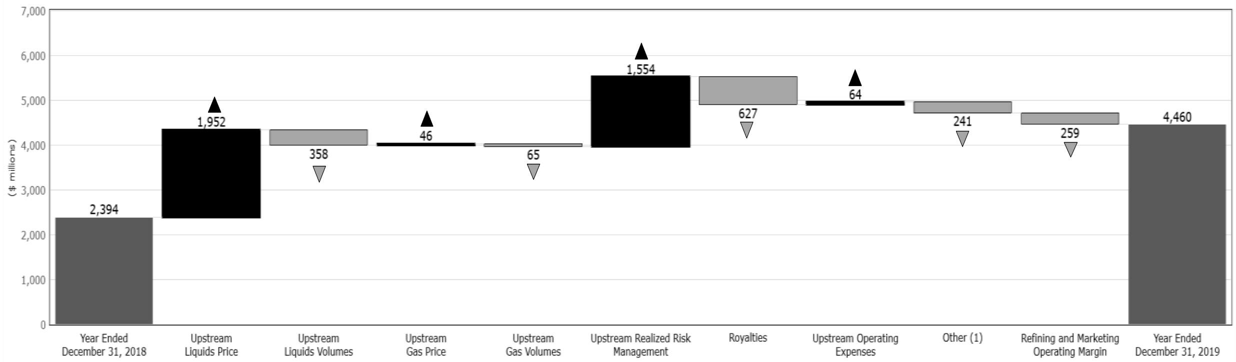
Operating Margin

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)	2019	2018 (1)	2017 (1)
Gross Sales	**22,042**	22,113	17,769
Less: Royalties	**1,172**	545	271
Revenues	**20,870**	21,568	17,498
Expenses			
Purchased Product	**8,844**	9,261	8,476
Transportation and Blending	**5,234**	5,969	3,760
Operating Expenses	**2,324**	2,367	1,956
Production and Mineral Taxes	**1**	1	1
Realized (Gain) Loss on Risk Management Activities	**7**	1,576	313
Operating Margin From Continuing Operations	**4,460**	2,394	2,992

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

Operating Margin From Continuing Operations 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.

Operating Margin from continuing operations increased in 2019 compared with 2018 primarily due to:

- A higher average crude oil sales price resulting from narrower differentials and an increase in our sales volumes at U.S. locations;
- A decrease in transportation and blending expenses due to lower condensate prices and a reduction in condensate volumes required for blending, partially offset by increased rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.;
- Lower upstream operating expenses; and
- Lower upstream realized risk management losses of $23 million (2018 – losses of $1,577 million).

These increases in Operating Margin were partially offset by:

- Higher royalties primarily due to Christina Lake achieving payout in August 2018 and higher realized prices;
- Lower sales volumes; and
- Lower Operating Margin from our Refining and Marketing segment primarily due to reduced realized crack spreads as a result of lower crude advantage.

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

Cash From Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations. Adjusted Funds Flow is defined as cash from operating activities excluding net change in other assets and liabilities and net change in non-cash working capital. Non-cash working capital is composed of accounts receivable, inventories, income tax receivable, accounts payable and income tax payable. Net change in other assets and liabilities is composed of site restoration costs and pension funding.

($ millions)	**2019**	2018 (1) (2)	2017 (1) (2)
Cash From Operating Activities	**3,285**	2,154	3,059
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(84)**	(72)	(107)
Net Change in Non-Cash Working Capital	**(355)**	552	252
Adjusted Funds Flow	**3,724**	1,674	2,914

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

Cash From Operating Activities and Adjusted Funds Flow were higher in 2019 compared with 2018 due to higher Operating Margin, lower general and administrative costs from a reduction in rent expense primarily due to the adoption of IFRS 16 and $60 million of severance costs incurred in 2018, and lower finance costs as a result of debt repayments, partially offset by a current income tax expense of $17 million compared with a recovery of $126 million in 2018. The change in non-cash working capital in 2019 was primarily due to an increase in accounts receivable and inventory, partially offset by an increase in accounts payable and a decrease in income tax receivable.

In 2018, the change in non-cash working capital was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable.

Operating Earnings (Loss)

($ millions)	2019	2018 [1]	2017 [1]
Earnings (Loss) From Continuing Operations, Before Income Tax	**1,397**	(3,926)	2,216
Add (Deduct):			
Unrealized Risk Management (Gain) Loss [2]	**149**	(1,249)	729
Non-Operating Unrealized Foreign Exchange (Gain) Loss [3]	**(787)**	593	(651)
Revaluation (Gain)	**-**	-	(2,555)
(Gain) Loss on Divestiture of Assets	**(2)**	795	1
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**757**	(3,787)	(260)
Income Tax Expense (Recovery)	**301**	(1,032)	(226)
Operating Earnings (Loss) From Continuing Operations	**456**	(2,755)	(34)

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Includes the reversal of unrealized (gains) losses recorded in prior periods.
(3) Includes unrealized foreign exchange (gains) losses on translation of U.S. dollar denominated notes issued from Canada and foreign exchange (gains) losses on settlement of intercompany transactions.

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

In 2019, Operating Earnings from continuing operations increased compared with 2018 primarily due to:

- Higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above;
- A lower exploration expense of $82 million compared with $2,123 million;
- A deferred tax recovery related to the write-down of Deep Basin E&E assets in 2018; and
- The 2018 provision of $629 million recognized for onerous contracts.

The increase in our Operating Earnings in 2019 was partially offset by realized foreign exchange losses of $401 million on the repurchase of our unsecured notes compared with losses of $214 million in 2018, higher depreciation, depletion, and amortization ("DD&A") primarily due to our right-of-use ("ROU") assets and a loss on the re-measurement of the contingent payment of $164 million (2018 – $50 million).

Net Earnings (Loss)

($ millions)	2019 vs. 2018	2018 vs. 2017
Net Earnings (Loss) From Continuing Operations, Comparative Year [1]	**(2,916)**	**2,268**
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**2,066**	**(598)**
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(1,398)**	**1,978**
Unrealized Foreign Exchange Gain (Loss)	**1,476**	**(1,506)**
Revaluation (Gain)	**-**	**(2,555)**
Re-measurement of Contingent Payment	**(114)**	**(188)**
Gain (Loss) on Divestiture of Assets	**797**	**(794)**
Expenses [2]	**573**	**(951)**
DD&A	**(118)**	**(293)**
Exploration Expense	**2,041**	**(1,235)**
Income Tax Recovery (Expense)	**(213)**	**958**
Net Earnings (Loss) From Continuing Operations, End of Year	**2,194**	**(2,916)**

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Includes Corporate and Eliminations realized risk management (gains) losses, general and administrative, onerous contract provisions, finance costs, interest income, realized foreign exchange (gains) losses, transaction costs, research costs, other (income) loss, net and Corporate and Eliminations revenues, purchased product, transportation and blending, and operating expenses.

In 2019, Net Earnings of $2,194 million from continuing operations increased from 2018 due to higher Operating Earnings, as discussed above, non-operating foreign exchange gains of $787 million compared with losses of $593 million in 2018, and the loss on the CPP divestiture in 2018. In 2019, we recorded a deferred income tax recovery of $671 million associated with the reduction in the Alberta corporate tax rate and a recovery of $387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our refining assets. In 2018, our deferred tax recovery was $884 million related to current period losses, including the write-down of Deep Basin E&E assets, and $78 million arising from an adjustment to the tax basis of our refining assets. These increases to our Net Earnings were partially offset by unrealized risk management losses of $149 million compared with gains of $1,249 million in 2018.

Net Earnings from discontinued operations for the year ended December 31, 2018 was $247 million and includes an after-tax gain of $220 million on the divestiture of the Suffield assets in the first quarter of 2018.

The Net Earnings (Loss) in 2018 decreased compared with 2017 primarily due to lower Operating Earnings, an after-tax revaluation gain of $1.9 billion on our pre-existing interest in the FCCL Partnership ("FCCL") recognized in 2017, non-operating foreign exchange losses compared with gains in 2017, and a loss on the divestiture of CPP, partially offset by unrealized risk management gains compared with losses, and a larger income tax recovery.

Capital Investment

($ millions)	**2019**	2018 [1]	2017 [1]
Oil Sands	**706**	887	973
Deep Basin	**53**	211	225
Refining and Marketing	**280**	208	180
Corporate and Eliminations	**137**	57	77
Conventional (Discontinued Operations)	**-**	-	206
Capital Investment [2]	**1,176**	1,363	1,661

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

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

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Selected Benchmark Prices and Exchange Rates [1]

Key performance drivers for our financial results include commodity prices, quality and location 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.

(US$/bbl, unless otherwise indicated)	**Q4 2019**	Q4 2018	**2019**	**Percent Change**	2018	2017
Brent						
Average	**62.50**	68.08	**64.18**	**(10)**	71.53	54.82
WTI						
Average	**56.96**	58.81	**57.03**	**(12)**	64.77	50.95
Average Differential Brent-WTI	**5.54**	9.27	**7.15**	**6**	6.76	3.87
WCS at Hardisty ("WCS")						
Average	**41.13**	19.39	**44.27**	**15**	38.46	38.97
Average Differential WTI-WCS	**15.83**	39.42	**12.76**	**(52)**	26.31	11.98
Average (C$/bbl)	**54.29**	25.60	**58.77**	**18**	49.81	50.56
WCS at Nederland						
Average	**51.47**	57.70	**55.56**	**(10)**	62.05	46.18
Average Differential WTI-WCS at Nederland	**5.49**	1.11	**1.47**	**(46)**	2.72	4.77
West Texas Sour ("WTS")						
Average	**57.26**	52.38	**56.27**	**(2)**	57.24	49.91
Average Differential WTI-WTS	**(0.30)**	6.43	**0.76**	**(90)**	7.53	1.04
Condensate (C5 @ Edmonton)						
Average	**53.01**	45.28	**52.86**	**(13)**	61.00	51.57
Average Differential WTI-Condensate (Premium)/Discount	**3.95**	13.53	**4.17**	**11**	3.77	(0.62)
Average Differential WCS-Condensate (Premium)/Discount	**(11.88)**	(25.89)	**(8.59)**	**(62)**	(22.54)	(12.60)
Average (C$/bbl)	**69.97**	59.74	**70.15**	**(11)**	79.02	66.89
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**64.83**	66.65	**70.55**	**(10)**	77.96	66.95
Chicago Ultra-low Sulphur Diesel ("ULSD")	**78.09**	84.25	**77.97**	**(10)**	86.75	69.09
Refining Margin: Average 3-2-1 Crack Spreads [2]						
Chicago	**12.27**	13.43	**16.00**	**-**	15.97	16.77
Group 3	**14.60**	14.57	**16.67**	**-**	16.74	16.61
Average Natural Gas Prices						
AECO [3] (C$/Mcf)	**2.34**	1.90	**1.62**	**6**	1.53	2.43
NYMEX (US$/Mcf)	**2.50**	3.64	**2.63**	**(15)**	3.09	3.11
Foreign Exchange Rate (US$ per C$1)						
Average	**0.758**	0.758	**0.754**	**(2)**	0.772	0.771
End of Period	**0.770**	0.733	**0.770**	**5**	0.733	0.797

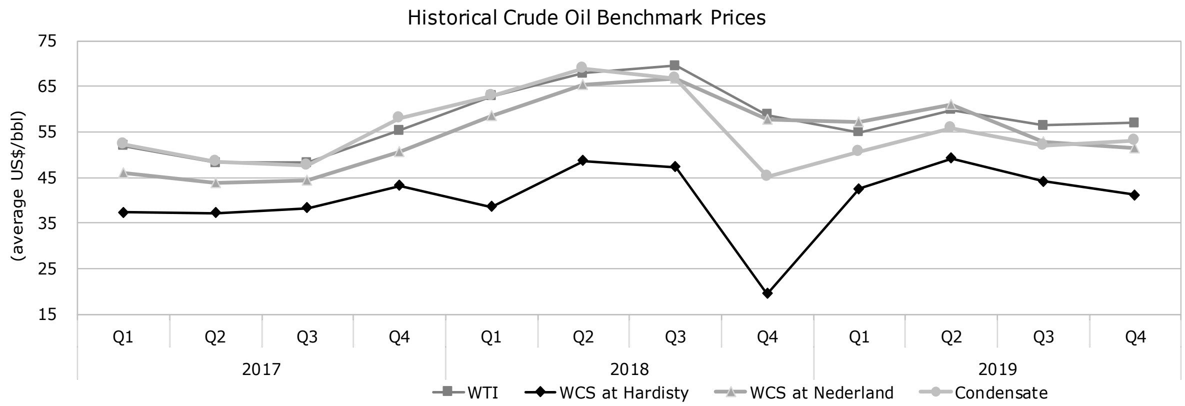
(1) *These benchmark prices are not our realized sales prices and represent approximate values. For our average realized sales prices and realized risk management results, refer to the Netback tables in the Reportable Segments sections of this MD&A.*
(2) *The average 3-2-1 Crack Spread is an indicator 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 2019, the average Brent and WTI crude oil benchmark prices were lower compared with 2018 as uncertainty from oversupply and decreased demand for crude oil due to U.S.-China trade tensions lowered crude oil benchmark pricing. Global prices were supported by the Organization of the Petroleum Exporting Countries ("OPEC")-led production cuts and by U.S.-led sanctions against Venezuela and Iran.

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 2019, the Brent-WTI differential increased as a result of strong supply growth from the Permian basin, which increased congestion at Cushing, Oklahoma.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. In 2019, the average WTI-WCS differential narrowed in response to production curtailments mandated by the Government of Alberta to address record high differentials in the fourth quarter of 2018 and high levels of crude oil in storage. Decreased production due to mandatory curtailments continues to support Alberta benchmark prices. WCS at Nederland is a heavy oil benchmark at the USGC which is representative of our pricing in relation to our increasing sales in the USGC. Heavy crude supply and demand remained tight globally and this was evident in strong pricing at the USGC throughout 2019. Key factors include production cuts between OPEC and their allies, and U.S. sanctions against Venezuela and Iran.



WTS is an important North American crude oil benchmark, representing the heavier, more sour counterpart to WTI crude oil, and is a primary component of the input feedstock at the Borger refinery. The differential between WTI and WTS benchmark prices narrowed in 2019, due to additional pipeline capacity coming online.

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 USGC condensate prices plus the cost to transport the condensate to Edmonton.

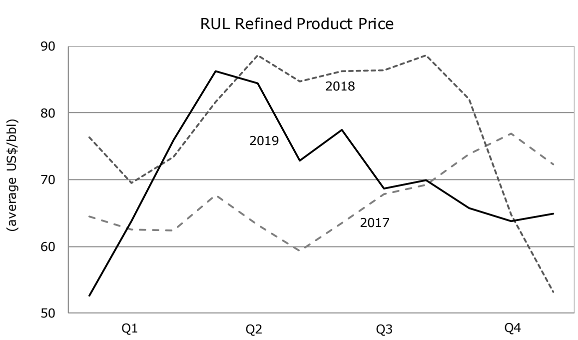
Average condensate benchmark prices were at a wider discount relative to WTI in 2019 compared with 2018 due to increasing North American supply and lower demand as production curtailments in Alberta were implemented.

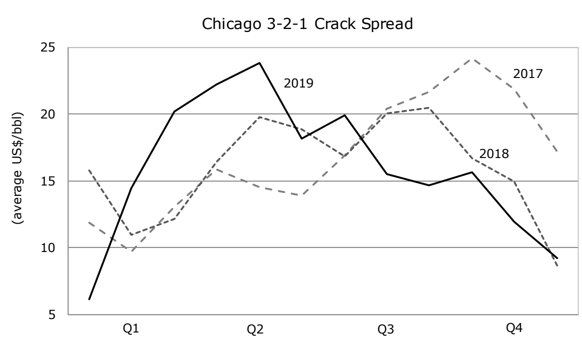
Refining Benchmarks

The Chicago Regular Unleaded Gasoline ("RUL") and Chicago Ultra-low Sulphur Diesel ("ULSD") benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel using current month WTI-based crude oil feedstock prices and valued on a last in, first out accounting basis.

Average Chicago refined product prices decreased in 2019 primarily due to lower global crude oil prices. As North American refining crack spreads are expressed on a WTI basis, while refined products are set by international prices, the strength of refining crack spreads in the U.S. Midwest and Midcontinent will reflect the differential between Brent and WTI benchmark prices.

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





Natural Gas Benchmarks

Average AECO prices strengthened during 2019 compared with 2018, however, they remained at low levels primarily due to little incremental demand and pipeline maintenance in the Alberta market. The Canada Energy Regulator recently approved a plan to get natural gas into storage during summer maintenance periods to improve intra Alberta supply and demand balances and reduce pricing pressure on AECO. Average NYMEX prices decreased compared with 2018 due to increased supply from the continuing development of U.S. shale gas and natural gas associated with crude oil plays.

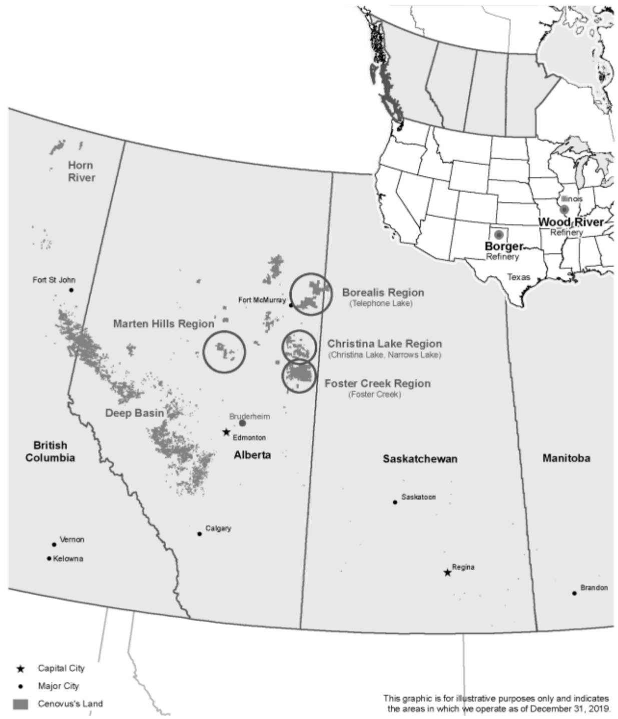
Foreign Exchange Benchmark

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.

The Canadian dollar on average weakened relative to the U.S. dollar in 2019, compared with 2018, resulting in a positive impact of approximately $470 million on our revenues in 2019. The strengthening of the Canadian dollar relative to the U.S. dollar as at December 31, 2019 compared with December 31, 2018, and the realization of foreign exchange losses on the repayment of our unsecured notes of $412 million, resulted in unrealized foreign exchange gains of $800 million on the translation of our U.S. dollar debt.

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

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations include adjustments for internal usage of natural gas production between segments, transloading services provided to the Oil Sands segment by the Company's rail terminal, crude oil production used as feedstock by the Refining and Marketing segment, and unrealized intersegment profits in inventory. Eliminations are recorded at transfer prices based on current market prices.

On May 17, 2017, we acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") their 50 percent interest in FCCL, and the majority of ConocoPhillips' western Canadian conventional assets in the Deep Basin in Alberta and British Columbia ("the Acquisition").

In 2017, Cenovus announced its intention to divest of its Conventional segment that included its heavy oil assets at Pelican Lake, the carbon dioxide ("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 a discontinued operation. As at January 5, 2018, all of the Conventional segment assets were sold. Refer to the Discontinued Operations section of this MD&A for more information.

Revenues by Reportable Segment

($ millions)	**2019**	2018	2017 (1)
Oil Sands	**9,695**	9,553	7,132
Deep Basin	**662**	832	514
Refining and Marketing	**10,513**	11,183	9,852
Corporate and Eliminations	**(689)**	(724)	(455)
	20,181	20,844	17,043

(1) Our 2017 results include 229 days of FCCL operations at 100 percent and 229 days of operations from the Deep Basin operations.

Oil Sands revenues increased slightly compared with 2018 due to higher realized crude oil pricing, partially offset by higher royalties and lower sales volumes. Deep Basin revenues declined in 2019 compared with 2018 due to lower sales volumes and realized natural gas liquids pricing, partially offset by lower royalties.

Refining and Marketing revenues declined in 2019 compared with 2018. Refining revenues decreased due to lower refined product pricing consistent with the decline in average refined product benchmark prices. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group increased in 2019 compared with 2018 due to higher crude oil and natural gas volumes partially offset by lower 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.

Overall, revenues increased in 2018 compared with 2017 primarily due to incremental sales volumes due to the Acquisition and higher refined product pricing, partially offset by lower realized crude oil and natural gas pricing and higher royalties.

OIL SANDS

In 2019, we:

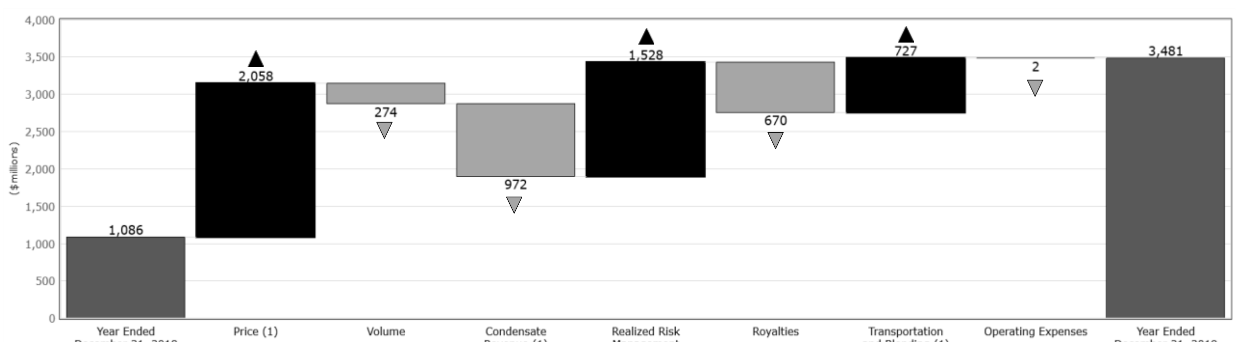
- Managed total production to mandated curtailment requirements;
- Completed construction of Christina Lake phase G in March, ahead of schedule and below the anticipated capital required;
- Safely and successfully completed our largest planned turnaround at Christina Lake;
- Generated Operating Margin of $3,481 million, an increase of $2,395 million compared with 2018 due to higher average realized sales prices, decreased transportation and blending costs, and realized risk management losses of $23 million compared with losses of $1,551 million in 2018, partially offset by lower sales volumes and higher royalties;
- Earned crude oil Netbacks of $27.72 per barrel, excluding realized risk management activities, a 41 percent increase compared with 2018; and
- Sold more than 25 percent of our Oil Sands production at sales locations outside of Alberta achieving higher realized sales prices.

Financial Results

($ millions)	2019	2018 (1)	2017 (1)
Gross Sales	**10,838**	10,026	7,362
Less: Royalties	**1,143**	473	230
Revenues	**9,695**	9,553	7,132
Expenses			
Transportation and Blending	**5,152**	5,879	3,704
Operating	**1,039**	1,037	934
(Gain) Loss on Risk Management	**23**	1,551	307
Operating Margin	**3,481**	1,086	2,187
Depreciation, Depletion and Amortization	**1,543**	1,439	1,230
Exploration Expense	**18**	6	888
Segment Income (Loss)	**1,920**	(359)	69

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

Operating Margin 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 2019, our realized crude oil sales price was $53.78 per barrel compared with $37.51 per barrel in 2018. While WTI benchmark was 12 percent lower than 2018, the narrowing of the WTI-WCS differential by 52 percent to average US$12.76 per barrel (2018 – US$26.31 per barrel), the narrower WCS-Christina Dilbit Blend ("CDB") differential, lower cost of condensate used in blending, and an increase in volumes sold outside of Alberta increased our crude oil sales price. In 2019, we sold more than 25 percent of our production at sales locations outside of Alberta, contributing to the increase in our realized sales prices.

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 decreases relative to the price of blended crude oil, our bitumen sales price increases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets and deliver it to the Edmonton hub. 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 sell our blended production. In a rising crude oil price environment, we expect to see a positive impact on our bitumen sales price as we are using condensate purchased at a lower price earlier in the year. The increase in our crude oil price also reflects the narrower WCS-Condensate premium of US$8.59 per barrel (2018 – premium of US$22.54 per barrel).

Production Volumes

(barrels per day)	**2019**	**Percent Change**	2018	Percent Change	2017
Foster Creek	**159,598**	**(1)**	161,979	30	124,752
Christina Lake	**194,659**	**(3)**	201,017	20	167,727
	354,257	**(2)**	362,996	24	292,479

Production at Foster Creek and Christina Lake was slightly lower compared with 2018 due to the mandated production curtailments. In the first and fourth quarters of 2018, we made the decision to operate both facilities at reduced production levels due to limited takeaway capacity and discounted heavy oil pricing.

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 percent 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 percent 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 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net profits are a function of sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

Foster Creek and Christina Lake are post-payout projects for determining royalties. Our Christina Lake property achieved payout in the third quarter of 2018.

Effective Royalty Rates

(percent)	**2019**	2018	2017
Foster Creek	**18.8**	18.0	11.4
Christina Lake	**21.6**	4.8	2.5

In 2019, royalties increased $670 million compared with 2018 due to Christina Lake achieving project payout in August 2018 and higher net profits as a result of the mandated curtailment, partially offset by lower annual average WTI benchmark pricing (which determines the royalty rate).

Expenses

Transportation and Blending

Transportation and blending costs decreased $727 million to $5,152 million in 2019. Blending costs decreased due to lower condensate costs and a decline in condensate volumes required for our lower production. Our condensate costs were higher than the average Edmonton benchmark price primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Transportation costs increased primarily due to an increase in volumes shipped by rail and higher pipeline tariff costs from increased U.S. sales. We transported over 25 percent of our volumes to U.S. destinations, either by pipeline or rail, allowing us to achieve better market prices.

Per-unit Transportation Expenses

Foster Creek per-unit transportation costs increased $3.36 per barrel to $11.70 per barrel due to higher sales volumes shipped by rail and pipeline to the U.S. and decreased total sales volumes, partially offset by IFRS 16 adoption impacts. Christina Lake per-unit transportation costs increased $1.39 per barrel to $6.64 per barrel as a result of higher sales volumes shipped by rail to the U.S. and decreased total sales volumes, partially offset by IFRS 16 adoption impacts. For further information on the adoption of IFRS 16 refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

Operating

Primary drivers of our operating expenses in 2019 were workforce, fuel, repairs and maintenance, chemical costs, and workovers. Total operating costs were relatively flat compared with 2018 due to higher fuel costs from higher natural gas prices and our decision to maintain steam production levels at pre-curtailment levels, and increased repairs and maintenance, offset by lower chemical costs, lower workforce costs and less workovers.

Per-unit Operating Expenses

($/bbl)	**2019**	**Percent Change**	2018 (1)	Percent Change	2017 (1)
Foster Creek					
Fuel	**2.47**	**16**	2.13	(13)	2.44
Non-fuel	**6.67**	**(2)**	6.84	(15)	8.02
Total	**9.14**	**2**	8.97	(14)	10.46
Christina Lake					
Fuel	**2.06**	**10**	1.87	(9)	2.06
Non-fuel	**5.27**	**11**	4.73	(1)	4.78
Total	**7.33**	**11**	6.60	(4)	6.84
Total	**8.15**	**7**	7.65	(9)	8.40

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

At Foster Creek and Christina Lake, per-barrel fuel costs increased due to lower sales volumes, higher natural gas prices and fuel consumption. Steam production levels were maintained at pre-curtailment levels during the year.

Per-barrel non-fuel operating expenses at Foster Creek decreased in 2019 compared with 2018 due to lower chemical costs, less workovers and lower workforce costs partially offset by lower sales volumes.

Per-barrel non-fuel operating expenses at Christina Lake increased in 2019 primarily due to lower sales volumes, increased repairs and maintenance and waste, fluid handling and trucking costs due to the planned turnaround in the second quarter, partially offset by lower chemical costs due to lower bitumen production and a volume related decrease in sulphur treating.

Netbacks (1)

	Foster Creek			Christina Lake		
($/bbl)	**2019**	2018 (2)	2017 (2)	**2019**	2018 (2)	2017 (2)
Sales Price	**57.21**	42.63	43.75	**50.91**	33.42	39.78
Royalties	**8.44**	6.25	4.00	**9.42**	1.37	0.87
Transportation and Blending	**11.70**	8.34	8.73	**6.64**	5.25	4.52
Operating Expenses	**9.14**	8.97	10.46	**7.33**	6.60	6.84
Netback Excluding Realized Risk Management	**27.93**	19.07	20.56	**27.52**	20.20	27.55
Realized Risk Management Gain (Loss)	**(0.16)**	(11.49)	(2.95)	**(0.19)**	(11.66)	(2.99)
Netback Including Realized Risk Management	**27.77**	7.58	17.61	**27.33**	8.54	24.56

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

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. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook ("COGE 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 transport it to market. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

Our average Netback, excluding realized risk management gains and losses, at Foster Creek and Christina Lake increased in 2019 compared with 2018, primarily due to higher realized sales prices, partially offset by higher per-unit royalties, transportation and blending costs, operating costs and lower sales volumes. The weakening of the Canadian dollar relative to the U.S. dollar compared with 2018 had a positive impact on our reported sales price of approximately $1.18 per barrel.

In 2019, we sold more than 25 percent of our Oil Sands production, at sales locations outside of Alberta, contributing to the increase in our realized sales prices and transportation and blending costs (2018 – approximately 18 percent of our Oil Sands production).

Risk Management

Risk management positions in 2019 resulted in realized losses of $23 million (2018 – realized losses of $1,551 million), consistent with average benchmark prices exceeding our contract prices on hedging contracts.

DD&A and Exploration Expense

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

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

In 2019, Oil Sands DD&A was $1,543 million and increased compared with 2018 due to an increase in our average depletion rate, partially offset by lower sales volumes and additional depreciation expense on our ROU assets. Our depletion rate increased as a result of higher future development costs due to additional capital required to improve recovery performance and develop thin pay volumes at Christina Lake and Foster Creek, as well as an increase in maintenance capital at Foster Creek. The average depletion rate for the year ended December 31, 2019 was approximately $11.15 per barrel (2018 – $10.60 per barrel).

Exploration expense of $18 million was recorded for the year ended December 31, 2019 (2018 – $6 million) related to previously capitalized E&E costs written off as the carrying value was not considered to be recoverable.

Capital Investment

($ millions)	**2019**	2018 (1)	2017 (1)
Foster Creek	**243**	379	455
Christina Lake	**362**	445	426
	605	824	881
Other (2)	**101**	63	92
Capital Investment (3)	**706**	887	973

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

In 2019, Oil Sands capital investment was $706 million, $181 million lower compared with 2018 mainly due to a continued focus on capital discipline, reduced spending on sustaining well programs, completion of Christina Lake phase G construction, a smaller stratigraphic test well program and deferred capital spending due to the mandatory curtailment. 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 completion of the phase G construction in March. Other capital investment related to advancing key initiatives and technical development costs.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1)		
	2019	2018	2017	**2019**	2018	2017
Foster Creek	**14**	43	96	**-**	14	41
Christina Lake	**18**	63	108	**11**	38	25
	32	106	204	**11**	52	66
Other	**26**	23	16	**11**	3	-
	58	129	220	**22**	55	66

(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

Oil Sands capital investment for 2020 is forecast to be between $865 million and $1,010 million. 2020 guidance dated December 9, 2019 is available on our website at cenovus.com.

Foster Creek capital investment for 2020 is forecast to be between $360 million and $410 million. We plan to continue focusing on sustaining capital related to existing production.

Christina Lake capital investment for 2020 is forecast to be between $310 million and $360 million focused on sustaining capital. Field construction of phase G was completed at the end of the first quarter of 2019 and is well positioned to bring on oil production in the first quarter of 2020 and ramp up towards its nameplate capacity of 50,000 barrels per day throughout 2020.

In 2020, we plan to spend capital on Foster Creek phase H, Christina Lake phase H and Narrows Lake to continue to advance each opportunity to sanction-ready status.

In 2020, our Technology and other capital investment, is forecast to be between $160 million and $190 million, 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.

DEEP BASIN

In 2019, we:

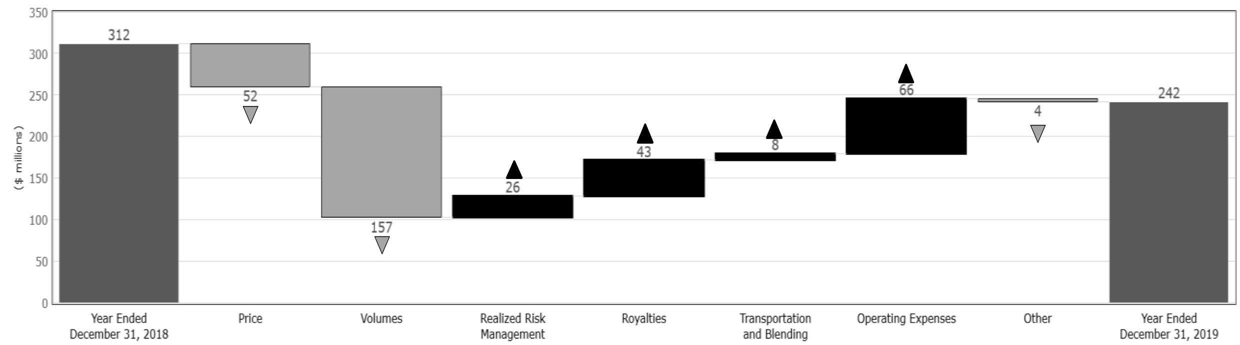
- Produced a total of 97,423 BOE per day, a decrease compared with 2018 due to natural declines from lower sustaining capital investment, the divestiture of CPP and temporary well shut-ins for low natural gas prices;
- Delivered total operating cost reductions by optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure;
- Generated Operating Margin of $242 million, a decrease of $70 million due to lower volumes and natural gas liquids prices, partially offset by lower operating expenses, royalties, realized risk management activities, and transportation and blending costs; and
- Earned a Netback of $6.02 per BOE, excluding realized risk management activities.

Financial Results

($ millions)	**2019**	2018 (1)	May 17 - December 31, 2017 (1)
Gross Sales	**691**	904	555
Less: Royalties	**29**	72	41
Revenues	**662**	832	514
Expenses			
Transportation and Blending	**82**	90	56
Operating	**337**	403	250
Production and Mineral Taxes	**1**	1	1
(Gain) Loss on Risk Management	**-**	26	-
Operating Margin	**242**	312	207
Depreciation, Depletion and Amortization	**319**	412	331
Exploration Expense	**64**	2,117	-
Segment Income (Loss)	**(141)**	(2,217)	(124)

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

Operating Margin Variance



Revenues

Price

	2019	2018	May 17 - December 31, 2017
Light and Medium Oil ($/bbl)	**65.70**	66.71	60.01
NGLs ($/bbl)	**26.36**	38.56	33.05
Natural Gas ($/mcf)	**2.01**	1.72	2.03
Total Oil Equivalent ($/BOE)	**17.95**	19.31	19.52

For the year ended December 31, 2019, revenues declined due to lower volumes and realized liquids sales prices, partially offset by an increase in our realized natural gas sale price. In 2019, revenues included $53 million of processing fee revenue related to our interests in natural gas processing facilities (2018 – $57 million). We do not include processing fee revenue in our per-unit pricing metrics or our Netbacks.

Production Volumes

	2019	2018	2017 (1)
Liquids			
Crude Oil (barrels per day)	**4,911**	5,916	3,922
NGLs (barrels per day)	**21,762**	26,538	16,928
	26,673	32,454	20,850
Natural Gas (MMcf per day)	**424**	527	316
Total Production (BOE/d)	**97,423**	120,258	73,492
Natural Gas Production (percentage of total)	**73**	73	72
Liquids Production (percentage of total)	**27**	27	28

(1) *From the closing of the Acquisition on May 17, 2017 to December 31, 2017, production averaged 117,138 BOE per day.*

Production in 2019 decreased from 2018 due to natural declines from lower sustaining capital investment, the divestiture of CPP and temporary well shut-ins for low natural gas prices.

CPP was sold on September 6, 2018 and produced approximately 6,523 BOE per day for the twelve months ended December 31, 2018.

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.

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 2019, our effective royalty rate was 8.7 percent for liquids (2018 – 12.8 percent) and 1.1 percent for natural gas (2018 – 3.6 percent) due to GCA royalty credits being higher than the royalty expenses, resulting in negative royalty rates in certain months of 2019, and declines in price and production.

Expenses

Transportation

Per unit transportation costs averaged $2.31 per BOE compared with $1.97 per BOE in 2018, due to higher pipeline tariffs. 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

Total operating costs decreased 16 percent to $337 million (2018 – $403 million) as a result of the divestiture of CPP, optimizing operations, focusing on well interventions, maintenance and repair activities and leveraging our infrastructure to lower the cost structure.

While total operating costs have declined significantly, per-unit operating costs increased slightly averaging $8.79 per BOE in 2019 (2018 – $8.58 per BOE). The increase in per-unit operating costs was driven by lower sales volumes, partially offset by decreased third-party processing fees due to less throughput and from leveraging our infrastructure to reduce fees paid, lower repairs and maintenance activity, decreased property tax and lease costs and lower workforce costs.

Netbacks

($/BOE)	2019	2018 (1)	May 17 - December 31, 2017 (1)
Sales Price	**17.95**	19.31	19.52
Royalties	**0.81**	1.64	1.54
Transportation and Blending	**2.31**	1.97	2.08
Operating Expenses	**8.79**	8.58	8.56
Production and Mineral Taxes	**0.02**	0.03	0.02
Netback Excluding Realized Risk Management	**6.02**	7.09	7.32
Realized Risk Management Gain (Loss)	**(0.01)**	(0.59)	-
Netback Including Realized Risk Management	**6.01**	6.50	7.32

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

Risk Management

Risk management activities in 2019 were minimal (2018 – realized losses of $26 million).

DD&A and Exploration Expense

We deplete crude oil and natural gas properties on a unit-of-production basis over proved reserves. The unit-of-production rate takes into account expenditures incurred to date, together with future development expenditures required to develop those proved reserves. This rate, calculated at an area level, is then applied to our sales volume to determine DD&A in a given period. We believe that this method of calculating DD&A charges each barrel of crude oil equivalent sold with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved reserves. The average depletion rate was approximately $9.15 per BOE year ended December 31, 2019 (2018 – $10.55 per BOE, respectively).

For the year ended December 31, 2019 total Deep Basin DD&A was $319 million (2018 – $412 million). The decrease was due to lower sales volumes and a lower depletion rate.

Exploration expense of $64 million was recorded for the year ended December 31, 2019 compared with $2.1 billion in 2018 resulting from previously capitalized E&E costs written off as a result of Management's review of the Deep Basin development plan.

Capital Investment

In 2019, we invested $53 million compared with $211 million in 2018. 2019 investment focused on the disciplined development of our Deep Basin assets, which included maintaining safe and reliable operations, as well as the completion and tie-in of well inventories from the previous year's development program.

($ millions)	2019	2018	May 17 - December 31, 2017
Drilling and Completions	**4**	111	152
Facilities	**20**	56	32
Other	**29**	44	41
Capital Investment (1)	**53**	211	225

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

Drilling Activity

In 2019, there were two net wells completed and three net wells tied-in. In 2018, there were 15 net horizontal wells drilled, 21 net wells completed, and 25 net wells tied-in.

Future Capital Investment

In 2020, Deep Basin capital investment is forecast to be between $80 million and $95 million.

We continue to take a disciplined approach to the development of our Deep Basin assets considering factors such as well inventory, pace of development, infrastructure constraints, economic thresholds and limited capital spending on the assets going forward. 2020 Guidance dated December 9, 2019 is available on our website at cenovus.com.

REFINING AND MARKETING

In 2019, we:

- Achieved crude oil runs averaging 443,000 barrels per day, consistent with 2018 and attained a record monthly crude oil run rate in July at Wood River;
- Increased rail volumes loaded at the Bruderheim crude-by-rail terminal, averaging 65,293 barrels per day compared with 37,988 barrels per day in 2018. We exited the year with loaded volumes averaging 101,014 barrels per day; and
- Generated Operating Margin of $737 million, a decrease of $259 million compared with 2018. While market crack spreads were relatively unchanged year over year, realized crack spreads were down due to narrowing medium sour and heavy crude oil differentials resulting in lower crude advantage.

Financial Results

($ millions)	2019	2018 (1)	2017 (1)
Revenues	**10,513**	11,183	9,852
Purchased Product	**8,844**	9,261	8,476
Gross Margin	**1,669**	1,922	1,376
Expenses			
Operating	**948**	927	772
(Gain) Loss on Risk Management	**(16)**	(1)	6
Operating Margin	**737**	996	598
Depreciation, Depletion and Amortization	**280**	222	215
Segment Income (Loss)	**457**	774	383

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

Refinery Operations (1)

	2019	2018	2017
Crude Oil Capacity (Mbbls/d) (2)	**482**	460	460
Crude Oil Runs (Mbbls/d)	**443**	446	442
Heavy Crude Oil	**177**	191	202
Light/Medium	**266**	255	240
Refined Products (Mbbls/d)	**466**	470	470
Gasoline	**223**	233	238
Distillate	**167**	156	149
Other	**76**	81	83
Crude Utilization (percent)	**92**	97	96

(1) Represents 100 percent of the Wood River and Borger refinery operations. Cenovus's interest is 50 percent.
(2) Effective January 1, 2020, our Refineries have crude oil nameplate capacity of 495,000 gross barrels per day.

On a 100 percent basis, the Refineries had total processing capacity in 2019 of 482,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil and 45,000 gross barrels per day of NGLs. Effective January 1, 2020, as a result of new maximum demonstrated rates in 2019, Wood River was re-rated, increasing our total crude oil processing nameplate capacity to 495,000 gross barrels per day including processing capability of up to 275,000 gross barrels per day of blended heavy 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 both WCS and WTS relative to WTI. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output in 2019 remained consistent compared with 2018. Operational performance in 2019 was impacted by the unplanned maintenance and outages, including a fire in the crude unit at Wood River in the first quarter, and planned turnaround activities at the Refineries in the fourth quarter. Both Refineries had major planned turnarounds in 2018.

Crude-By-Rail Terminal

We continue to increase total rail volumes loaded at our Bruderheim crude-by-rail terminal. In 2019, we loaded an average of 65,293 barrels per day (45,324 barrels per day of our volumes) from our Bruderheim crude-by-rail terminal compared with an average of 37,988 barrels per day (28,531 barrels per day of our volumes) in 2018.

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 2019, Refining and Marketing gross margin decreased $253 million. While market crack spreads were relatively unchanged year over year, realized crack spreads were down due to narrowing medium sour and heavy crude oil differentials which resulted in lower crude advantage, partially offset by higher margins on fixed priced products associated with a lower benchmark WTI, and a reduction in the cost of RINs. Our gross margin was positively impacted by approximately $37 million for the year ended December 31, 2019, due to the weakening of the Canadian dollar relative to the U.S. dollar.

For the year ended December 31, 2019, the cost of RINs was $99 million (2018 – $131 million). RIN costs declined, primarily due 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 2019 were maintenance, labour and utilities. Refining operating expenses increased due to the weakening of the Canadian dollar relative to the U.S dollar. Marketing operating expense increased $14 million due to higher rail transportation and workforce costs.

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 60 years. The service lives of these assets are reviewed on an annual basis. ROU assets are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. Refining and Marketing DD&A was $280 million compared with $222 million in 2018. The increase is primarily attributable to depreciation of our ROU assets which commenced January 1, 2019 on the adoption of IFRS 16.

Capital Investment

($ millions)	**2019**	2018 (1)	2017 (1)
Wood River Refinery	**128**	119	114
Borger Refinery	**100**	85	54
Marketing	**52**	4	12
Capital Investment	**280**	208	180

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

Capital expenditures in 2019 focused primarily on capital maintenance projects and yield enhancements as well as strategic rail initiatives and infrastructure.

In 2020, we expect to invest between $285 million and $330 million and will continue to focus on capital maintenance, reliability work and yield improvement projects. Our 2020 guidance dated December 9, 2019 is available on our website at cenovus.com.

CORPORATE AND ELIMINATIONS

In 2019, our risk management activities resulted in unrealized risk management losses of $149 million (2018 – gains of $1,249 million).

Expenses

($ millions)	2019	2018 (1)	2017 (1)
General and Administrative	**336**	391	300
Onerous Contract Provisions	**(5)**	629	8
Finance Costs	**511**	627	645
Interest Income	**(12)**	(19)	(62)
Foreign Exchange (Gain) Loss, Net	**(404)**	854	(812)
Revaluation (Gain)	**-**	-	(2,555)
Transaction Costs	**-**	-	56
Re-measurement of Contingent Payment	**164**	50	(138)
Research Costs	**20**	25	36
(Gain) Loss on Divestiture of Assets	**(2)**	795	1
Other (Income) Loss, Net	**(11)**	(12)	(5)
	597	3,340	(2,526)

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

General and Administrative

Primary drivers of our general and administrative expenses were workforce costs, employee long-term incentive costs and operating costs associated with our real estate portfolio. In 2019, general and administrative expenses decreased $55 million primarily due to lower rent expense of $42 million compared with $134 million in 2018 primarily from the adoption of IFRS 16, lower headcount and minimal severance costs in 2019 compared with $60 million of severance costs in 2018, partially offset by higher employee long-term incentive costs (2019 – $98 million; 2018 – $9 million).

Onerous Contract Provisions

In 2019, due to the adoption of IFRS 16, onerous contract provisions are composed of non-lease components of real estate contracts which consist of operating costs and unreserved parking. In 2018, onerous contract provisions included the lease components of base rent and reserved parking as well as the non-lease components. For further information on the adoption of IFRS 16 refer to Note 4 of the Consolidated Financial Statements.

In 2019, we recorded a non-cash recovery for onerous contracts of $5 million, due to an update in the underlying assumptions associated with certain Calgary office space (2018 – expense of $629 million).

Finance Costs

In 2019, finance costs decreased by $116 million compared with 2018 due to the significant reduction of total debt and a discount of $63 million on the repurchase of unsecured notes in 2019, partially offset by an increase in interest of $82 million related to lease liabilities from the adoption of IFRS 16.

The weighted average interest rate on outstanding debt for the year ended December 31, 2019 was 5.1 percent (2018 – 5.1 percent).

Foreign Exchange

($ millions)	2019	2018	2017
Unrealized Foreign Exchange (Gain) Loss	**(827)**	649	(857)
Realized Foreign Exchange (Gain) Loss	**423**	205	45
	(404)	854	(812)

In 2019, unrealized foreign exchange gains of $827 million were recorded primarily as a result of the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at December 31, 2019 was stronger compared with December 31, 2018. For the year ended December 31, 2019, realized foreign exchange losses of $423 million, were recorded primarily as a result of the recognition of foreign exchange losses from the repurchase of debt.

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 is $6 million for each dollar that the WCS price exceeds $52 per barrel. There are no maximum payment terms. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment.

The contingent payment is accounted for as a financial option. The fair value of $143 million as at December 31, 2019 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. For the year ended December 31, 2019, a non-cash re-measurement loss of $164 million was recorded.

As at December 31, 2019, average WCS forward pricing for the remaining term of the contingent payment is $46.57 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately $41.20 per barrel and $54.60 per barrel.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements, office furniture, and ROU assets. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. ROU assets (real estate assets) are depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term. DD&A in 2019 was $107 million (2018 – $58 million). The increase in DD&A compared with 2018 was due to depreciation expense on our ROU assets.

Income Tax

($ millions)	**2019**	2018	2017
Current Tax			
Canada	**14**	(128)	(217)
United States	**3**	2	(38)
Current Tax Expense (Recovery)	**17**	(126)	(255)
Deferred Tax Expense (Recovery)	**(814)**	(884)	203
Total Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)

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

($ millions)	**2019**	2018	2017
Earnings (Loss) From Continuing Operations Before Income Tax	**1,397**	(3,926)	2,216
Canadian Statutory Rate (percent)	**26.5**	27.0	27.0
Expected Income Tax Expense (Recovery) From Continuing Operations	**370**	(1,060)	598
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(52)**	(57)	(17)
Non-Taxable Capital (Gains) Losses	**(38)**	89	(148)
Non-Recognition of Capital (Gains) Losses	**(39)**	87	(118)
Adjustments Arising from Prior Year Tax Filings	**4**	3	(41)
Recognition of Previously Unrecognized Capital Losses	**-**	-	(68)
Recognition of U.S. Tax Basis	**(387)**	(78)	-
Change in Statutory Rates	**(671)**	-	(275)
Non-Deductible Expenses	**-**	3	(5)
Other	**16**	3	22
Total Tax Expense (Recovery) From Continuing Operations	**(797)**	(1,010)	(52)
Effective Tax Rate (percent)	**(57.1)**	25.7	(2.3)

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.

For the year ended December 31, 2019, a current tax expense was recorded compared with a recovery in 2018 and 2017 due to the carry back of losses to recover tax paid in previous years. The maximum recovery was reached in 2018.

In 2019, the Government of Alberta enacted a reduction in the provincial corporate tax rate from 12 percent to eight percent over four years. As a result, we recorded a deferred income tax recovery of $671 million for the year ended December 31, 2019. In addition, we have recorded a deferred income tax recovery of $387 million due to an internal restructuring of our U.S. operations resulting in a step-up in the tax basis of our refining assets.

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 the Company's refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in 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 was recorded in 2017 due to the revaluation gain of our pre-existing interest in connection with the Acquisition, net of a reduction of the U.S. federal corporate income tax rate from 35 percent to 21 percent reducing our deferred income tax liability and the impact of E&E write-downs.

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.

Capital Investment

Capital expenditures of $137 million for the year ended December 31, 2019 focused primarily on the build-out of office space at Brookfield Place Calgary and information technology capital.

In 2020, we expect to invest between $90 million and $100 million, which includes continued investments in technology and equipment to further modernize our workplace, improve our cost structure and better manage risk. Guidance dated December 9, 2019 is available on our website at cenovus.com.

DISCONTINUED OPERATIONS

On January 5, 2018, we completed the sale of the Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. After-tax earnings from discontinued operations for the year ended December 31, 2018 were $27 million. An after-tax gain on discontinuance of $220 million was recorded on the sale.

QUARTERLY RESULTS

Our results over the last four quarters were impacted primarily by mandatory production curtailments and the last eight quarters were impacted by volatility in commodity prices. Light oil benchmark prices remained depressed throughout the majority of 2019, consistent with the substantial fall in the price of WTI in the fourth quarter of 2018, due to continued uncertainty from oversupply, decreased demand and trade tensions compared with the price improvements throughout the first three quarters of 2018. The mandatory production curtailments significantly narrowed light-heavy crude oil differentials in Alberta and reduced crude price spread between the USGC and Alberta in 2019 compared with 2018. As a result, our Operating Margin from continuing operations was $864 million in the fourth quarter of 2019, a substantial increase from $135 million in the fourth quarter of 2018. Net Earnings from continuing operations was $113 million compared with a loss of $1,350 million in 2018.

Selected Operating and Consolidated Financial Results

($ millions, except per share amounts)	2019				2018 [1]			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production Volumes								
Liquids (barrels per day)	**400,329**	380,699	371,390	370,983	354,592	408,950	423,340	395,474
Natural Gas (MMcf per day)	**403**	407	432	458	469	520	572	558
Total Production (BOE per day)	**467,448**	448,496	443,318	447,270	432,714	495,608	518,609	488,561
Total Production From Continuing Operations (BOE per day)	**467,448**	448,496	443,318	447,270	432,713	495,592	518,530	487,464
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**456**	465	474	375	477	492	464	349
Refined Products (Mbbls/d)	**477**	485	501	402	502	518	490	369
Revenues	**4,838**	4,736	5,603	5,004	4,545	5,857	5,832	4,610
Operating Margin from Continuing Operations [2]	**864**	1,080	1,277	1,239	135	1,191	911	157
Cash From Operating Activities								
From Continuing Operations	**740**	834	1,275	436	488	1,258	506	(134)
Total	**740**	834	1,275	436	485	1,259	533	(123)
Adjusted Funds Flow [3]	**678**	916	1,082	1,048	(36)	977	774	(41)
Operating Earnings (Loss) from Continuing Operations [3]	**(164)**	284	267	69	(1,670)	(41)	(292)	(752)
Per Share ($) [4]	**(0.13)**	0.23	0.22	0.06	(1.36)	(0.03)	(0.24)	(0.61)
Net Earnings (Loss)								
From Continuing Operations	**113**	187	1,784	110	(1,350)	(242)	(410)	(914)
Per Share ($) [4]	**0.09**	0.15	1.45	0.09	(1.10)	(0.20)	(0.33)	(0.74)
Total Net Earnings (Loss)	**113**	187	1,784	110	(1,356)	(241)	(418)	(654)
Per Share ($) [4]	**0.09**	0.15	1.45	0.09	(1.10)	(0.20)	(0.34)	(0.53)
Capital Investment [5]	**317**	294	248	317	276	271	292	524
Dividends	**77**	60	62	61	62	61	62	60
Per Share ($)	**0.0625**	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500	0.0500

(1) *IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.*
(2) *Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements, in Notes 1 and 7 of the Interim Consolidated Financial Statements and defined in this MD&A.*
(3) *Non-GAAP measure defined in this MD&A.*
(4) *Represented on a basic and diluted per share basis.*
(5) *Includes expenditures on PP&E, E&E assets, and assets held for sale.*

Fourth Quarter 2019 Results Compared With the Fourth Quarter 2018

Production Volumes

Total production from continuing operations increased eight percent in the fourth quarter of 2019 compared with 2018. In the fourth quarter of 2018, we decided to restrict oil sands production rates in response to takeaway capacity constraints and the wide heavy oil differentials. In the fourth quarter of 2018, the WTI-WCS differential averaged US$39.42 per barrel and reached a record of US$52.00 per barrel.

In the fourth quarter of 2019, we sold 181,366 barrels per day, approximately 35 percent, of our Oil Sands production at sales locations outside of Alberta compared with 99,041 barrels per day, approximately 20 percent, in the fourth quarter of 2018.

Deep Basin production in the fourth quarter of 2019 decreased 12 percent to 93,317 BOE per day mainly due to natural declines from lower sustaining capital investment.

Refining and Marketing Operations

Crude oil runs of 456,000 gross barrels per day and refined product output of 477,000 gross barrels per day were lower compared with the same period in 2018 due to planned turnaround activities and a crude supply constraint at Wood River as a result of the Keystone pipeline leak, partially offset by optimization of the total crude input slate. In the fourth quarter of 2018 both Refineries operated above nameplate capacity of 460,000 gross barrels per day.

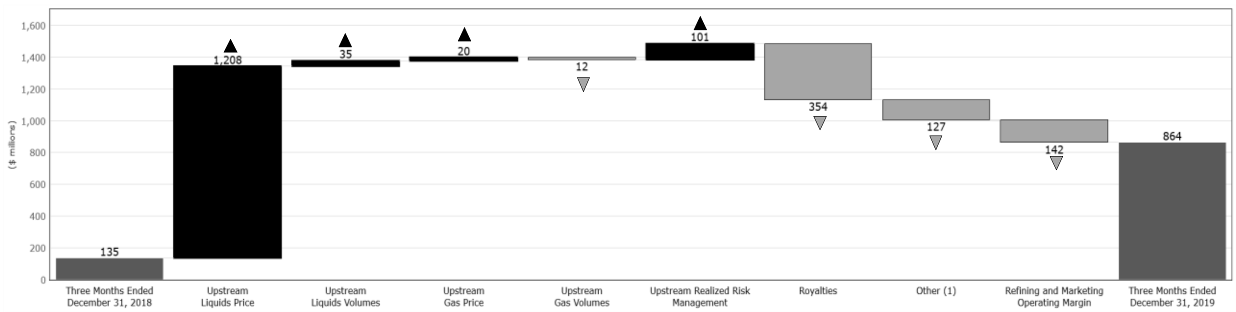
In the fourth quarter of 2019 we increased total rail volumes loaded at our Bruderheim crude-by-rail terminal by loading an average of 89,630 barrels per day (71,708 barrels per day of our volumes) compared with an average of 70,323 barrels per day (51,475 barrels per day of our volumes) in 2018.

Revenues

Revenues increased $293 million in the fourth quarter of 2019 primarily due to higher realized liquids sales pricing of $47.12 per barrel compared with $13.26 per barrel in 2018, and increased sales volumes.

The increase was partially offset by higher royalties, decreased refining revenues due to lower refined product pricing consistent with the decline in average refined product benchmark prices, lower volumes and decreased revenues from third-party crude oil and natural gas sales undertaken by the marketing group.

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.

Operating Margin

Operating Margin from continuing operations increased in the fourth quarter of 2019 compared with 2018 due to a higher average liquids sales price as a result of narrower differentials, increased sales volumes and upstream realized risk management gains of $15 million (2018 – losses of $86 million).

These increases were partially offset by:

- Higher royalties primarily due to our higher realized crude oil sales price, partially offset by lower annual average WTI benchmark pricing;
- An increase in our transportation and blending costs due to an increase in rail transportation costs and pipeline tariffs due to higher volumes shipped to the U.S.; and
- Lower Operating Margin from our Refining and Marketing segment due to lower crude advantage, decreased crude oil runs, lower market crack spreads and higher operating expenses.

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow increased in the fourth quarter of 2019 compared with the same period in 2018, primarily due to higher Operating Margin, as discussed above, and a reduction in rent expense due to the adoption of IFRS 16. The increase in Cash From Operating Activities was partially offset by a lower tax recovery, realized risk management gains of $23 million in 2018 related to interest rate swaps and changes in non-cash working capital.

The change in non-cash working capital in the fourth quarter of 2019 was primarily due to an increase in accounts payable and a decrease in income tax receivable, partially offset by an increase in accounts receivable and inventory. For 2018, the change in non-cash working capital was primarily due to a decrease in accounts receivable and inventory, partially offset by a decrease in accounts payable and income tax payable.

Operating Earnings (Loss)

Operating Loss from continuing operations decreased in the three months ended December 31, 2019 compared with 2018 primarily due to exploration expense of $72 million compared with $2,115 million in the fourth quarter of 2018, as well as higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above. These decreases were partially offset by a re-measurement loss of $27 million on the contingent payment compared with a gain of $361 million in 2018 and higher employee long-term incentive costs.

Net Earnings (Loss)

Net Earnings from continuing operations of $113 million increased for the three months ended December 31, 2019 compared with a Net Loss of $1,350 million in 2018. The change was primarily due to a lower Operating Loss, as discussed above, and non-operating foreign exchange gains of $258 million compared with losses of $296 million in 2018. These increases to our Net Earnings from continuing operations were partially offset by unrealized risk management gains of $8 million compared with unrealized gains of $741 million in 2018 and a deferred income tax recovery of $24 million compared with a deferred tax recovery of $580 million.

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2019 was $317 million, $41 million higher compared with the fourth quarter of 2018, primarily due to advancing key initiatives and technical developments as well as higher spending on rail initiatives and infrastructure.

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.

Reserves

As at December 31, 2019 (before royalties)	**Bitumen [(1)]** (MMbbls)	**Light and Medium Oil** (MMbbls)	**NGLs** (MMbbls)	**Conventional Natural Gas [(2)]** (Bcf)	**Total** (MMBOE)
Proved	**4,826**	**9**	**60**	**1,242**	**5,103**
Probable	**1,594**	**8**	**37**	**783**	**1,768**
Proved plus Probable	**6,420**	**17**	**97**	**2,025**	**6,871**

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.*

Developments in 2019 compared with 2018 include:

- Bitumen proved reserves decreasing five million barrels as additions from improved performance in Oil Sands were more than offset by current year production;
- Bitumen proved plus probable reserves decreasing nine million barrels as additions from improved performance in Oil Sands were more than offset by current year production;
- Light and medium oil proved reserves decreasing three million barrels as minor additions were more than offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;
- Light and medium oil proved plus probable reserves were unchanged as minor additions were offset by technical revisions attributed to changes to the Deep Basin development plan, and current year production;
- NGLs proved and proved plus probable reserves decreasing 12 million barrels and 19 million barrels, respectively, as minor additions were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production; and
- Conventional natural gas proved and proved plus probable reserves decreasing by 271 billion cubic feet and 529 billion cubic feet, respectively, as additions were more than offset by reductions due to technical revisions attributed to changes to the Deep Basin development plan, and current year production.

The reserves data is presented as at December 31, 2019 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, 2020. Comparative information as at December 31, 2018 uses the January 1, 2019 IQRE Average Forecast prices and costs.

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, 2019. 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)	**2019**	2018	2017
Cash From (Used In)			
Total Operating Activities	**3,285**	2,154	3,059
Total Investing Activities	**(1,432)**	(613)	(12,866)
Net Cash Provided (Used) Before Financing Activities	**1,853**	1,541	(9,807)
Financing Activities	**(2,413)**	(1,410)	6,515
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**(35)**	40	182
Increase (Decrease) in Cash and Cash Equivalents	**(595)**	171	(3,110)

As at December 31,	**2019**	2018	2017
Cash and Cash Equivalents	**186**	781	610
Net Debt	**6,513**	8,383	8,903
Committed and Undrawn Credit Facility	**4,235**	4,500	4,500

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

Cash From (Used In) Operating Activities

For the year ended December 31, 2019, cash generated by operating activities increased mainly due to:

- Higher Operating Margin, as discussed in the Operating and Financial Results section of this MD&A;
- A decrease in general and administrative costs, due to a decrease in rent expense primarily from the adoption of IFRS 16 and $60 million of severance costs recognized in 2018; and
- A decrease in finance costs, as discussed in the Corporate and Eliminations section of this MD&A.

The increases in cash from operating activities for the year ended December 31, 2019 were partially offset a current income tax expense in 2019 compared with a recovery in 2018 and changes in non-cash working capital, as discussed in the Operating and Financial Results section of this MD&A.

Excluding risk management assets and liabilities and the current portion of the contingent payment, our working capital was $839 million at December 31, 2019 compared with $450 million at December 31, 2018.

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

Cash From (Used In) Investing Activities

Cash used in investing activities was higher in 2019 compared with 2018 primarily due to proceeds from the divestiture of CPP and the Suffield assets in 2018, partially offset by decreased capital investment in 2019.

Cash From (Used In) Financing Activities

In 2019, cash was used in financing activities primarily for the repayment of debt. We repaid US$1.8 billion of unsecured notes for cash consideration of US$1.7 billion ($2.3 billion). Total debt as at December 31, 2019 was $6,699 million (December 31, 2018 – $9,164 million).

In 2018, cash was used in financing activities primarily for the repayment of US$876 million ($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.

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.

Dividends

In 2019, we paid dividends of $0.2125 per common share or $260 million (2018 – $0.20 per common share or $245 million). Our Board declared a first quarter dividend of $0.0625 per share, payable on March 31, 2020, to common shareholders of record as of March 13, 2020. 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 2020. 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.

Moody's Investors Service ("Moody's") changed their outlook on our Ba1 rating to positive from stable in the fourth quarter. In addition to making progress towards re-establishing an investment grade credit rating at Moody's 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, 2019:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**186**
Committed Credit Facility – Tranche A	**November 2023**	**3,035**
Committed Credit Facility – Tranche B	**November 2022**	**1,200**

Committed Credit Facility

We have a committed credit facility in place that consists of a $1.2 billion tranche and a $3.3 billion tranche. In the fourth quarter of 2019, we amended the committed credit facility to extend the maturity date of the $1.2 billion tranche to November 30, 2022 and the maturity date of the $3.3 billion tranche to November 30, 2023. As at December 31, 2019, $265 million was drawn on our committed credit facility.

Base Shelf Prospectus

Cenovus has in place a base shelf prospectus which expires in October 2021. As at December 31, 2019, US$5.0 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions. Refer to Note 23 of the Consolidated Financial Statements for more details on our Base Shelf Prospectus.

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 and short-term investments. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, E&E Write-down, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing twelve-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

As at December 31,	**2019**	2018	2017
Net Debt to Capitalization (1) (percent)	**25**	32	31
Net Debt to Adjusted EBITDA (2)	**1.6x**	5.9x	2.8x

(1) Net Debt to Capitalization is defined as Net Debt divided by Net Debt plus Shareholders' Equity.
(2) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.

A reconciliation of Adjusted EBITDA, and the calculation of Net Debt to Adjusted EBITDA can be found in Note 23 of the Consolidated Financial Statements.

Cenovus targets a Net Debt to Adjusted EBITDA ratio of less than 2.0 times over the long-term. This ratio may periodically be above the target due to factors such as persistently low commodity prices. 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 our common shares for cancellation, 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.

As at December 31, 2019, Cenovus's Net Debt to Adjusted EBITDA was 1.6 times. Net Debt to Adjusted EBITDA decreased compared with 2018 as result of significant repayments of our debt as mentioned in the Cash From (Used In) Financing Activities above.

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

Refer to Note 32 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, 2020	Units Outstanding (thousands)	Units Exercisable (thousands)
Common Shares [1]	**1,228,870**	**N/A**
Stock Options	**31,459**	**27,083**
Other Stock-Based Compensation Plans	**16,606**	**1,339**

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

Capital Investment Decisions

Our approach to capital allocation includes evaluating all opportunities using specific rigorous criteria based on a US$45.00 per barrel WTI price and US$13.00 per barrel WTI-WCS differential environment, which we believe are the bottom-of-the-cycle commodity prices, with the objective of maintaining a prudent and flexible capital structure and strong balance sheet metrics. This approach helps position us to be financially resilient in times of lower cash flows. Balance sheet strength will continue to be a top priority and we plan to direct the majority of our Free Funds Flow towards debt reduction until we reach our longer-term Net Debt target of $5.0 billion. This level of Net Debt approximates a Net Debt to EBITDA ratio of two times at bottom-of-the-cycle commodity prices. As we progress towards our longer-term Net Debt target, we will also consider opportunities for shareholder returns in the form of dividend increases and share repurchases.

Our capital allocation priorities include committed capital priorities and discretionary capital priorities. Committed capital priorities include safe and reliable operations, sustaining and maintenance capital for our existing business operations, funding our base dividend, and funding our targeted five percent to 10 percent annual dividend growth.

Discretionary capital allocation priorities, as we continue to reduce our Net Debt are:

- First, to continue to deleverage and reach our Net Debt target;
- Second, to support the potential sale of ConocoPhillips's ownership of Cenovus's common shares; and
- Third, balance other opportunistic share repurchases with disciplined investment in growing our business, while continuing to strengthen our balance sheet.

Refer to the Liquidity and Capital Resources section of this MD&A for further information.

($ millions)	2019	2018 [1] [2]	2017 [1] [2]
Adjusted Funds Flow	**3,724**	1,674	2,914
Total Capital Investment	**1,176**	1,363	1,661
Free Funds Flow [3]	**2,548**	311	1,253
Cash Dividends	**260**	245	225
	2,288	66	1,028

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Policies section in this MD&A.
(2) Includes our Conventional segment, which has been classified as a discontinued operation.
(3) 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 2020 to be funded from our internally generated cash flows and our cash balance on hand.

Contractual Obligations and Commitments

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

On January 1, 2019, the Company adopted IFRS 16, which resulted in the recognition of lease liabilities related to operating leases on the balance sheet. These liabilities were previously reported as commitments. For a reconciliation of our commitments as at December 31, 2018 to our lease liabilities as at January 1, 2019, see Note 4 of the Consolidated Financial Statements.

As at December 31, 2019, total commitments were $23 billion, of which $21 billion are for various transportation and storage commitments. Terms are up to 20 years subsequent to the date of commencement and should help align the Company's future transportation requirements with anticipated production growth. Transportation and storage commitments include future commitments relating to railcar and storage tank leases of $31 million and $11 million, respectively, that have not yet commenced. The railcar leases are expected to commence in 2020 with lease terms between six and eight years and the storage tank leases are expected to commence in 2020 with lease terms of five years.

($ millions)	Expected Payment Date 2020	2021	2022	2023	2024	Thereafter	Total
Commitments							
Transportation and Storage [1]	1,005	959	1,026	1,456	1,381	15,672	**21,499**
Real Estate [2]	35	36	38	39	42	662	**852**
Other Long-Term Commitments	104	44	36	34	28	108	**354**
Total Commitments [3]	1,144	1,039	1,100	1,529	1,451	16,442	**22,705**
Other Obligations							
Long-term Debt (Principal and Interest)	344	344	994	1,174	291	9,326	**12,473**
Decommissioning Liabilities	57	44	44	39	41	2,437	**2,662**
Contingent Payment	79	50	19				**148**
Lease Liabilities (Principal and Interest) [4]	277	243	223	196	214	1,544	**2,697**
Total Commitments and Obligations	1,901	1,720	2,380	2,938	1,997	29,749	**40,685**

(1) *Includes transportation commitments of $13 billion (December 31, 2018 – $14 billion) that are subject to regulatory approval or have been approved but are not yet in service.*
(2) *Relates to the non-lease components of lease liabilities consisting of operating costs and unreserved parking for office space. Excludes committed payments for which a provision has been provided.*
(3) *Contracts undertaken on behalf of WRB are reflected at our 50 percent interest.*
(4) *Lease contracts related to office space, railcars, storage assets, drilling rigs and other refining and field equipment.*

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, 2019, there were outstanding letters of credit aggregating $364 million issued as security for performance under certain contracts (December 31, 2018 – $336 million).

Legal Proceedings

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

Contingent Payment

In connection with the Acquisition and related to our 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, 2019, the estimated fair value of the contingent payment was $143 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 pursue our strategic priorities, respond to changes in our operating environment, pay dividends to our shareholders and fulfill our obligations (including debt servicing requirements) 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, including a Risk Matrix. 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 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 or 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; and 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 control over financial reporting ("ICFR"). Changes in financial management and/or market conditions could impact a number of factors including, but not limited to, Cenovus's cash flows, Cenovus's ability to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization, 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: global and regional supply of and demand for crude oil; global economic conditions including factors impacting global trade; 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 or SPA for crude-by-rail, and compliance or non-compliance with imposed crude oil production curtailments or SPA for crude-by-rail; enforcement of government or environmental regulations; public sentiment towards the use of non-renewable resources, including crude oil; political stability; market access constraints and transportation interruptions (pipeline, marine or rail) and access to markets; prices and availability of alternate fuel sources; outbreak of war; terrorist threats; 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 and availability of alternate sources of energy; government or environmental regulations; public sentiment towards the use of non-renewable resources, including natural gas; and economic conditions. Refined product prices are impacted by a number of factors including, but not limited to: global and regional supply and demand for refined products; market competitiveness; levels of refined product inventories; refinery availability; planned and unplanned refinery maintenance; weather conditions; current and potential future environmental regulations pertaining to the production and use of refined products; prices and availability of alternate sources of energy; public sentiment towards the use refined products; and the availability of alternate fuel sources. In addition, and relating to the level of future demand (and corresponding price levels) for each of crude oil, natural gas and refined products, there has been a significant increase in focus recently on the timing for and pace of the transition to a lower-carbon economy. Governments, financial institutions, environmental and governance organizations, institutional investors, social and environmental activists, and individuals, are increasingly seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively are intended to or have the effect of accelerating the reduction in the global consumption of carbon-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from carbon-based forms of energy. This focus and resulting trends will likely affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. However it is not currently possible to predict the timelines for and precise effects of this transition to a potential lower-carbon economy, which will depend on a multitude of factors including the ability to develop adequate replacement sources of energy, technology development and adaptation including in the area of transportation electrification, the ability to conceptualize, develop and commercialize technologies for the production, storage and distribution of adequate alternative supplies of alternative energy, consumption patterns, global growth and industrial activity, in order to predict the longer term demand trends for carbon-based energy 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 domestic or 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 generally 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 our ability to meet guidance targets, the value of our assets, our cash flows, our ability to maintain our business and to fund projects including, but not limited to, the continued development of our oil sands properties. A substantial decline in these commodity prices or extended period of low commodity prices may result in an inability to meet all of our financial obligations as they come due, 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 then in effect), unutilized long-term transportation commitments and/or low utilization levels at Cenovus's refineries. Fluctuations in commodity prices, associated price differentials and refining margins impact our financial condition, results of operations, cash flows, growth, access to capital and cost of borrowing.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, and 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, or if the costs of our development of such resources significantly increases, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts, market access commitments and generally through our access to committed credit facilities. Financial instruments undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 35 and 36 of the Consolidated Financial Statements.

Development and Operating Costs

Our financial outlook and performance is significantly affected by the cost of developing, sustaining 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; changes in regulatory compliance costs; 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 Management Policy, which has been approved by the Board, allows Management to use derivative instruments to help mitigate the impact of changes in crude oil and natural gas prices, crude oil differentials, diluent or condensate supply prices and differentials, refining margins, 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; lack of market liquidity; 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 undertaken within our refining business by the operator, Phillips 66, are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3, 35 and 36 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

($ millions)	2019 Realized	2019 Unrealized	2019 Total	2018 Realized	2018 Unrealized	2018 Total
Crude Oil	**23**	**143**	**166**	1,577	(1,219)	358
Refining	**(16)**	**1**	**(15)**	(1)	(5)	(6)
Interest Rate	**1**	**7**	**8**	(23)	(26)	(49)
Foreign Exchange	**(1)**	**(2)**	**(3)**	1	1	2
(Gain) Loss on Risk Management	**7**	**149**	**156**	1,554	(1,249)	305
Income Tax Expense (Recovery)	**(2)**	**(36)**	**(38)**	(422)	336	(86)
(Gain) Loss on Risk Management, After Tax	**5**	**113**	**118**	1,132	(913)	219

In 2019, we incurred realized losses on crude oil risk management activities as the settlement prices exceeded our contract prices. Unrealized losses were recorded on our crude oil financial instruments in the twelve months ended December 31, 2019 primarily due to the realization of settled positions and changes in market prices.

Sensitivities – Risk Management Positions

The following table summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices, 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 on our open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$5.00 per bbl Applied to WTI and Condensate Hedges	**3**	**(3)**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**5**	**(5)**

For further information on our risk management positions, see Notes 35 and 36 of 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*.

Financial instruments also expose Cenovus to the risk of a loss from adverse changes in the market value of financial instruments or if we are unable to fulfill our delivery obligations related to the underlying physical transaction. Financial instruments may limit the benefit to Cenovus if commodity prices, interest or foreign exchange rates change. These risks are managed through hedging limits authorized according to our *Market Risk Management Policy*.

Exposure to Counterparties

In the normal course of business, we enter into contractual relationships with suppliers, partners, lenders and other counterparties for the provision and sale of goods and services. If such counterparties do not fulfill their contractual obligations on a timely basis or at all, 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, investor or lender sentiment towards our business and/or the industry in which we operate or credit rating, or significant unanticipated expenses, may impede our ability to secure and maintain cost-effective financing. An inability to access capital, on terms acceptable to Cenovus or at all, could affect our ability to make future capital expenditures, to maintain desirable ratios of debt (and Net Debt) to Adjusted EBITDA as well as debt (and Net Debt) to capitalization 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 capital that could have less favourable terms.

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 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 capital structure are regularly evaluated by 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.

Dividend Payment and Share Repurchase

The payment of dividends, continuation of Cenovus's dividend reinvestment plan and any potential share repurchase by Cenovus of its common shares is at the discretion of the Board, and 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 other risk factors set forth in this MD&A.

Disclosure Controls and Procedures and ICFR

Based on their inherent limitations, disclosure controls and procedures and ICFR 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. However, there can be no assurance as to the amount, if any, or timing of recovery under our insurance policies in connection with losses associated with these events and risks. Although we maintain insurance for a number of risks and hazards, we may not be insured or fully insured against all losses or liabilities that could arise from our assets or 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 rail networks and our refineries are reliant on various pipelines and rail networks 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 and rail 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 or rail network to operate, or 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, will require tank cars used to transport crude-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.

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 in respect of our assts or operations, and it cannot be guaranteed that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. Our operations could also be interrupted by natural disasters or other events beyond our control. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operation and cash flows.

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, develop and produce 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, including renewable energy sources which may become more prevalent in the future.

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; our ability to finance capital and expenses; our 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, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. 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.

There is also a risk of cyber-related fraud whereby perpetrators attempt to take control of electronic communications or attempt to impersonate internal personnel or business partners to divert payments and financial assets to accounts controlled by the perpetrators. If a perpetrator is successful in bypassing Cenovus's cyber-security measures and business process controls, such cyber-related fraud could result in financial losses, remediation and recovery costs, and an adverse reputational impact.

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 key personnel and 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. In recent years there has been an increase in climate change related litigation in various jurisdictions including the U.S. and Canada, asserting various claims, including that energy producers contribute to climate change, that such entities are not reasonably managing business risks associated with climate change, and that such entities have not adequately disclosed business risks of climate change. While many of the climate change related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change related litigation against energy producers including us. The outcome of any such litigation is uncertain and may materially impact our financial condition or results of operations. Moreover, unfavourable 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

Some Aboriginal groups have established or asserted Aboriginal treaty, title and rights to portions of Western Canada, including British Columbia and Alberta. There are outstanding Aboriginal and treaty rights claims, which may include Aboriginal title claims, on lands where we operate, and such claims, if successful, could have a material adverse impact on our operations or pace of growth. 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 Aboriginal people and any associated accommodations 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 considered by the Government of Alberta and affirmed in legislation by the Government of British Columbia. The federal government has committed to introducing legislation to implement UNDRIP. 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 and operations, posing risks and creating uncertainty with respect to project regulatory approval timelines and requirements, and operating conditions. The Government of British Columbia is developing an action plan to harmonize provincial laws with UNDRIP.

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 increased 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; environmental and 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. Cenovus currently has direct A&R liability. 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 Fund, which is administered by 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.

The Supreme Court of Canada's decision in Redwater 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, resulting in additional or more stringent A&R related covenants being imposed on borrowers, and resulting 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 British Columbia Oil and Gas Commission has a similar liability management program to manage public liability. The program requires permit holders to carry the financial risks and regulatory responsibility of their operations by requiring permit holders who are considered high risk to submit a security deposit. 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.

Alberta's Modernized Royalty Framework ("MRF") applies to all conventional wells spud on or after January 1, 2017. Wells spud prior to January 1, 2017 will continue to operate under the previous Alberta Royalty Framework until December 31, 2026 when all conventional wells will be subject to MRF. The Government of Alberta's Royalty Guarantee Act, which took effect on July 18, 2019, guarantees that the royalty structure in place when a well is drilled remains in place for at least 10 years. The Act applies to current crude oil, oil sands and natural gas royalty frameworks, including crude oil, pentanes, methane, ethane, propane and butane. It also confirms that the transition to the MRF for wells spud prior to January 1, 2017 will occur in 2026. The MRF does not apply to oil sands production, which has its own separate royalty framework.

Further changes to any of the royalty regimes in Alberta, changes to the existing royalty regimes in British Columbia, or changes to how existing royalty regimes are interpreted and applied by the applicable governments, 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.

Canada-United States-Mexico Agreement ("CUSMA")

On December 20, 2019, Canada, the U.S. and Mexico signed an Amending Protocol that revises the CUSMA, which is intended to replace the North American Free Trade Agreement ("NAFTA"). Mexico and the U.S. have ratified the revised CUSMA, and Canada is currently working through its domestic ratification procedures. While the outcome of the ratification process is not certain, it is anticipated that the CUSMA will come into force around July 1, 2020. According to a Government of Canada technical summary of negotiated outcomes related to the energy sector, under CUSMA, the rule of origin applicable to heavy oil containing diluent has been relaxed to allow up to 40 percent of non-originating diluent in pipelines for transportation of crude oil without affecting the originating status of the product, which will allow Canadian products to more easily qualify for duty-free treatment when imported into the U.S. The related CUSMA side letter on energy between Canada and the U.S. also promotes regulatory transparency and non-discrimination in access to or use of energy infrastructure, which may potentially benefit the Canadian heavy oil industry.

However, CUSMA also reduces the availability of investor-state dispute settlement mechanisms for Canadian investments in the U.S. or U.S. investments in Canada. For three years after the termination of NAFTA, existing "legacy investments" will maintain their access to investor-state dispute settlement under NAFTA Chapter 11. Thereafter, under CUSMA this dispute settlement mechanism will not be available for Canadian investments in the U.S. or U.S. investments in Canada. If CUSMA is not ratified, this may alter the terms of trade for energy products and affect the sale and transportation of Cenovus's products within North America, which could have a negative impact on Cenovus's business, financial condition and results from operations.

Environmental 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 affect 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 as well as shift hydrocarbon demand toward relatively lower carbon sources, increase compliance costs, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Greenhouse Gas Emissions & Targets

Our ability to lower scope 1 and 2 GHG emissions (see Definitions section of this MD&A) on both an absolute basis and in terms of intensity in our operations and in respect of Cenovus's target of reducing GHG emissions intensity by 30 percent and holding overall emissions flat by 2030, and our long-term ambition of reaching net-zero emissions by 2050 (which is inherently less certain due to the longer time frame and certain factors outside of our control, including the commercial application of future technologies) are subject to numerous risks and uncertainties and our actions taken in implementing such targets may also expose us to certain additional and/or heightened financial and operational risks.

A reduction in GHG emissions relies on the commercial viability and scalability of emission reduction strategies and related technology and products. In the event that we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our GHG 2030 targets or 2050 ambition on the current timelines, or at all.

In addition, achieving our GHG 2030 targets and 2050 ambition will require capital expenditures and company resources, with the potential that expectations regarding the costs required to achieve these targets and ambitions differ from our original estimates.

Additional ESG Focus Areas and Targets

Cenovus's other ambitious ESG targets, not related directly to GHG emissions, which include its target to spend $1.5 billion with Indigenous owned or operated businesses, to reclaim 1,500 abandoned well sites, to invest $40 million to restore an area of land within caribou ranges greater than the amount of land disturbed by our activity in those ranges and to achieve a fresh water intensity of 0.1 barrels per barrel of oil equivalent, all by the end of 2030, depend significantly on its ability to execute its current business strategy, related milestones and schedules which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate as outlined in this MD&A. There is also a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets may fail to materialize, may cost more to achieve or may not occur within the anticipated time periods. In addition, there are risks that the actions taken by Cenovus in implementing targets and goals for ESG focus areas may have a negative impact on our existing business, operations and increase capital expenditures, which could have a negative impact on our future operating and financial results. There is a risk that some or all of the expected benefits and opportunities of achieving the various ESG targets may fail to materialize.

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.

The *Technology Innovation and Emissions Reduction* ("TIER") system replaces the *Carbon Competitiveness Incentive Regulation* ("CCIR") (effective January 1, 2020). The TIER system has been deemed equivalent to the federal output-based pricing system for 2020, but in the absence of an equivalent economy-wide price on carbon, the federal fuel charge will apply to Alberta-based facilities outside the TIER system. The TIER system will automatically apply to industrial sources that emit greater than 100,000 tonnes of GHG emissions per year. Facilities that do not meet the emissions threshold of 100,000 tonnes of GHG emissions per year can opt into the TIER system, thereby avoiding the federal fuel charge, if they compete against a facility regulated under the TIER system or emit over 10,000 tonnes of GHG emissions and belong to a sector with high emissions intensity and trade exposure. Companies in the conventional oil and gas sector will be regulated under the TIER system.

Facilities subject to TIER are required to meet an emissions intensity benchmark which is set based on industry or facility 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. Both of Cenovus's Christina Lake SAGD facility and Foster Creek SAGD facility are subject to TIER (and previously CCIR). Cenovus does not expect the changes in the emissions intensity calculations under TIER to result in a material financial impact.

The British Columbia *Carbon Tax Act* sets a carbon price of $40 per tonne of CO_2e on fuel combustion and is expected to increase by $5 per tonne of CO_2e per year, reaching the federal target carbon price of $50 on April 1, 2021. The federal government has stated this program meets the requirements of the federal *Greenhouse Gas Pollution Pricing Act*. The CleanBC Program for Industry directs an amount equal to the incremental carbon tax paid by industry above $30/tonne into incentives to reduce emissions. 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. British Columbia has entered into an equivalency agreement with the Government of Canada, declaring that the federal methane regulations do not apply in British Columbia. Alberta is attempting to negotiate an equivalency agreement with the Government of Canada.

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; and 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 emissions reductions may not be technically or economically feasible to implement, in whole or in part, and failure to have access to resources or technology to meet emissions 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 and reputation.

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. As an oil sands producer, we are not directly regulated and are not expected to have a compliance obligation for carbon intensity reduction requirements for liquid fuels. Refiners, importers, and fuel distributors in these jurisdictions are required to comply with the legislation.

Environment and Climate Change Canada published a proposed regulatory framework in 2017 for the Clean Fuel Standard under the *Canadian Environmental Protection Act, 1999*. The proposed new regulatory framework would impose lifecycle carbon intensity requirements for certain liquid, gaseous and solid fuels that are used in transportation, industry and buildings, and establish rules relating to the trading of compliance credits. 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.

Carbon intensity requirements under the Clean Fuel Standard regulation would become more stringent over time and would be differentiated between different types of renewable fuels to reflect the associated emissions reduction potential. Regulated parties, which may include fuel producers and importers, would have some flexibility with respect to how to achieve lower carbon fuels in Canada.

Environment and Climate Change Canada has since published a Regulatory Design Paper for the Clean Fuel Standard in December 2018 and a Proposed Regulatory Approach for the Clean Fuel Standard in June 2019. These documents present additional details of the proposed regulatory design of the Clean Fuel Standard. The Canadian Government is reporting that new regulations under the Clean Fuel Standard are targeted to come into force on January 1, 2022 (for liquid fuels) and January 1, 2023 (for gaseous and solid fuel regulations). The Canadian federal government has indicated that over time, the new Clean Fuel Standard would replace the current Renewable Fuels Regulations.

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.

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 and the *Energy Policy Act of 2005*, among other things, the Environmental Protection Agency implemented the Renewable Fuel Standard program that mandates that a certain volume of renewable fuel replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel sold or introduced in the U.S. Obligated parties, including refiners or importers of gasoline or diesel fuel, achieve compliance with targets set by the U.S. Environmental Protection Agency by blending certain types of renewable fuel into transportation fuel, or by purchasing credits (RINs) from other obligated parties on the open market. The mandate requires the volume of renewable fuels blended into finished petroleum products to increase over time until 2022. 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 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* have 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 identified within the Draft Provincial Woodland Caribou Range Plan, including: (a) recovering caribou habitat through restoration of legacy seismic lines and inactive oil and gas infrastructure; (b) working with oil and gas companies to reschedule development; (c) developing stringent requirements for new oil and gas approvals, and seismic exploration programs; (d) developing Regional Access Management Plans for all land users within and directly adjacent to caribou ranges; (e) consolidating forest harvesting operations in pre-defined areas per decade; and (f) identifying conservation areas in some ranges where impacts to existing industrial tenure are avoided and lands contribute to caribou recovery. The Draft Provincial Woodland Caribou Range Plan was drafted in 2017, but has not yet been finalized. More recent initiatives include negotiation of conservation agreements under Section 11 of the *Species at Risk Act* (which codifies concrete measures to support the conservation of the species and the protection of its critical habitat), and e) the creation of sub-regional ministerial task forces to develop recommendations to government on sub-regional plans for the Cold Lake, Bistcho and Upper Smokey areas.

If plans and actions undertaken by the provinces are deemed insufficient to support caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. Further, 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 at the Federal Court of Canada 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.* The litigation has been adjourned while the parties discuss potential settlement of the matter.

The extent and magnitude of any adverse impacts of the legislation on project development and operations cannot be estimated at this time as uncertainty exists with respect to whether plans and actions undertaken by the provinces will be deemed sufficient to support caribou recovery.

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 stationary engines are regulated in accordance with specified performance standards. We anticipate that the MSAPR will result in adverse impacts including but not limited to capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter 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 including but not limited to capital investment related to retrofit existing facilities and increased operating costs.

Federal Review of Environmental and Regulatory Processes

In 2016, the Government of Canada commenced a review of the federal environmental and regulatory processes administered under the *National Energy Board Act*, *Canadian Environmental Assessment Act*, *Fisheries Act*, and the *Navigation Protection Act*. This review culminated on August 28, 2019 with the coming into force of Bill C-69, *An Act to enact the Impact Assessment Act* and the *Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts,* Bill C-68 amends the *Fisheries Act,* and came into force in August 2019.

The *Fisheries Act* amendments restore the previous prohibition against "harmful alteration, disruption or destruction of fish habitat" and the prohibition against causing the death of fish by means other than fishing. The amendments also introduce several new requirements that expand the scope of protection and role of Indigenous groups and interests. The prohibitions against the death of fish, and the harmful alteration, disruption or destruction of fish habitat may result in increased permitting requirements where the Company's operations potentially impact fish or habitat.

The changes to the *Navigation Protection Act*, including its renaming to the *Canadian Navigable Waters Act*, expands its scope to all navigable waters, creates greater oversight for navigable waters and, consistent with the *Fisheries Act*, introduces requirements to expand the scope of protection and the role of Indigenous groups and interests. The broader application of the *Canadian Navigable Waters Act* may result in increased permitting requirements where the Company's operations potentially impact navigable waters. These amendments came into force in August 2019.

The *Impact Assessment Act* ("IAA"), replaces the *Canadian Environmental Assessment Act* and establishes 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 IAA expands the assessment considerations beyond the environment to include health, economy, social, gender and as well as considerations related to sustainability and Canada's climate change commitments. The *Canadian Energy Regulator Act* replaces the National Energy Board with the Canadian Energy Regulator and modifies the regulator's role.

Of note, the revised Project List outlined in the *Physical Activities Regulations* enabled under the IAA captures in situ oil sands facilities but provides an exemption for a project proposed within a province in which there is a legislated limit on GHG emissions produced by the oil sands sector. For as long as the provincial government maintains the cap on oil sands emissions in Alberta and the cap has not been reached, Cenovus's in situ oil sands project should be exempted from the application of the new federal impact assessment system. However, other types of projects would undergo a federal assessment.

The extent and magnitude of any adverse impacts resulting from these legislative changes on project development and operations cannot be reliably or accurately estimated at this time as uncertainty exists with respect to the implementation of the Acts and their accompanying regulations. Increased environmental assessment 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. The *Environmental Assessment Act* came into force in December 2019 and allows wide discretionary powers to the Minister to designate a project for review. The Act also sets out to integrate the principles embedded in the UNDRIP, including by seeking consensus in review processes from Indigenous communities; how this will be implemented is being defined through the work of an Indigenous Implementation Committee.

On November 26, 2019, British Columbia passed Bill 41, draft legislation to implement UNDRIP, becoming the first Canadian province to do so. Government fact sheets on the legislation emphasize that the Province retains authority for making decisions in the public interest and the legislation does not provide for the ability to veto decisions on resource projects.

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 was released in February 2019 with 97 recommendations which are to be implemented in a phased approach that will include increased monitoring, aquifers mapping and efforts to improve the regulatory regime.

In January 2018, the Government of British Columbia proposed restrictions on the increase of diluted bitumen transportation as part of amendments to the *Environmental Management Act* and its regulations to improve preparedness, response and recovery from potential oil spills. The proposed restrictions could have had a material adverse impact on our ability to transport diluted bitumen through British Columbia. 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 hazardous substances (defined as heavy oil or bitumen) within the province, as set out in the proposed amendments. In May of 2019, the British Columbia Court of Appeal unanimously held that the proposed amendments were beyond the jurisdiction of the Government of British Columbia. In January 2020, the Supreme Court of Canada unanimously upheld the decision of the British Columbia Court of Appeal.

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, utility and make-up water at our SAGD facilities, as well as 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 under the *Water Sustainability Act*. Most groundwater and surface water use (other than domestic use) requires a water licence. Annual water rental fees are established by the regulations to the *Water Sustainability Act*, and additional supporting regulations continue to be proposed and may be 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 the 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

Developers of oil and gas assets in wetlands areas may be required to obtain an approval under the *Water Act* and, pursuant to the Alberta Wetland Policy, 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 in these areas 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. In these cases, we are required to comply with requirements for wetland reclamation or, where permanent wetland loss will occur, make payment to an in-lieu fee program, or take 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 conventional 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 investors and other stakeholders, to recruit and retain staff, and to be a credible, trusted company. Any actions we take that influence public or key stakeholder opinions have the potential to 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 on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels activists (with a focus on oil sands) targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands 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. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect Cenovus's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of our insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, we may not be able to extend or renew our existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, changes in environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, 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.

Amount of Contingent Payments

In connection with the Acquisition, we agreed to make contingent payments under certain circumstances. The amount of contingent payments vary depending on the Canadian dollar WCS price from time to time during the five year period following the closing of the Acquisition (May 17, 2017), and such payments may be significant. In addition, in the event that such further 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, its financial results 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.

U.S. Tax Risk

In the U.S., the Tax Cuts and Jobs Act which was signed into law on December 22, 2017, made substantial changes to the U.S. tax system. Regulatory guidance from the U.S. Treasury as to how certain of these changes are to be implemented was not complete as at December 31, 2019. There is a possibility that when final Treasury guidance is issued, negative consequences to Cenovus could result.

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"), now Ovintiv Inc., 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, *"Joint Arrangements"*. As such, Cenovus recognized its share of the assets, liabilities, revenues and expenses in its consolidated results. Subsequent to the Acquisition (refer to Note 9 of the Consolidated Financial Statements), Cenovus controls FCCL, as defined under IFRS 10, "*Consolidated Financial Statements*" ("IFRS 10") and, accordingly, FCCL has been consolidated.

In determining the classification of its joint arrangements under IFRS 11, the Company 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.
- 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 the Company'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 Cash-Generating Units ("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 terminal, railcars, storage tanks, 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.

Determining the Lease Term

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

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to 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 fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Deep Basin segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

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 the Company's 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 Company's 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.

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD 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 (Level 3). 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, 2019 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2019, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2020	2021	2022	2023	2024	Average Annual Increase Thereafter (percent)
WTI (US$/barrel)	61.00	63.75	66.18	67.91	69.48	2.0
WCS (C$/barrel)	57.57	62.35	64.33	66.23	67.97	2.1
Edmonton C5+ (C$/barrel)	76.83	79.82	82.30	84.72	86.71	2.0
AECO (1) (C$/Mcf)	2.04	2.32	2.62	2.71	2.81	2.1

(1) *Assumes gas heating value of one million British thermal units 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.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream 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.

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 judgment 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 commodity prices, reserves 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.

Changes in Accounting Policies

Adoption of IFRS 16

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

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

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

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

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

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

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

- Decrease in purchased product of $34 million;
- Decrease to transportation and blending costs of $87 million;
- Decrease to operating costs of $5 million;
- Decrease to general and administrative expenses of $58 million;
- Increase to DD&A expense of $168 million; and
- Increase in finance expenses of $82 million.

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 4 of the Consolidated Financial Statements.

Uncertain Tax Positions

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

New Accounting Standards and Interpretations not yet Adopted

A number of new standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2020 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2019. These standards and interpretations are not expected to have a material impact on the Company's 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 ICFR and disclosure controls and procedures ("DC&P") as at December 31, 2019. 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 ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2019.

The effectiveness of our ICFR was audited as at December 31, 2019 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, 2019.

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.

SUSTAINABILITY

At Cenovus, sustainability is essential to the way we do business. It means creating a safe and inclusive workplace, partnering with local and Indigenous communities, and innovating to minimize our impact on the environment. We believe striking the right balance among environmental, economic and social considerations creates long-term value.

We recognize that operating our business sustainably requires transparency with our stakeholders about our ESG performance. After conducting comprehensive research, we have identified four key ESG focus areas for the company: climate & GHG emissions, Indigenous engagement, land & wildlife and water stewardship. Supported by our leading safety practices and strong governance structure, we believe these four ESG focus areas are the most material to our company and are of the greatest importance to our stakeholders.

To support our sustainability performance, 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 2018 ESG report in July 2019 to report on our management efforts and performance across the areas within our CR policy, as well as other environment, social and governance topics that are important to our stakeholders. Our ESG report is available on our website at cenovus.com.

OUTLOOK

In 2020, we expect to see continued commodity price volatility and market access constraints for heavy oil exiting Alberta. Transportation challenges will continue to negatively impact heavy oil prices, demonstrating the need for increased rail export capabilities and approved pipeline projects to proceed as soon as possible. While our production levels have been impacted by the government mandated production curtailments, the resulting narrowing price differentials are anticipated to continue to have a positive impact on our cash flows. Curtailment restrictions are expected to remain in place until the end of 2020, with curtailment relief for crude volumes that are transported in the form of crude-by-rail and new conventional wells drilled. Increased crude-by-rail volumes and incremental pipeline space should help ease takeaway capacity constraints. In the first half of 2019 we achieved first steam from Christina Lake phase G but subsequently deferred oil production ramp up to comply with the curtailment order. With the implementation of the SPA program Cenovus is well positioned to bring on Christina Lake phase G oil production in the first quarter of 2020 and ramp up towards its nameplate capacity of 50,000 barrels per day throughout 2020.

We continue to look for ways to increase our margins through strong operating performance and cost leadership, while focusing on safe and reliable operations. Proactively managing our market access commitments and opportunities assists with our goal of reaching a broader customer base to secure a higher sales price for our crude oil.

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

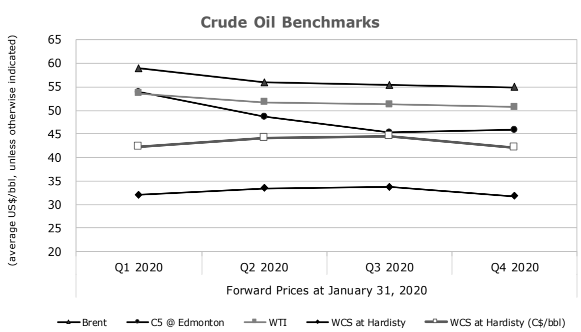
The following outlook commentary is focused on the next twelve months.

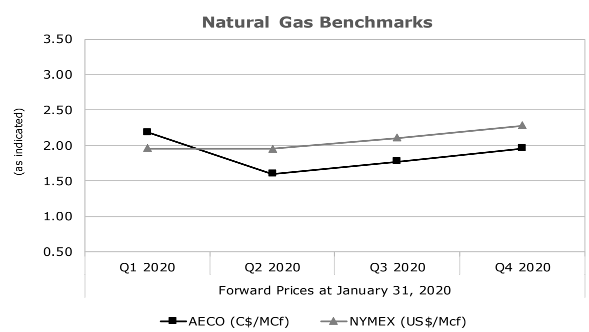
Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for light crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and global demand impacts amid evolving trade conflicts;
- Crude oil price volatility is expected to increase slightly due to increased Middle East geopolitical risks and as global inventories draw down to OPEC stated target of the 2010-2014 average;
- Continuing OPEC supply cuts and U.S. led sanctions on Venezuela and Iran will be supportive of the narrowing of global light-heavy crude oil price differentials;
- We expect that the WTI-WCS differential in Alberta will remain largely tied to the extent to which production curtailments in Alberta remain in place, the completion of the Trans Mountain Expansion Project, the potential start-up of Enbridge Inc.'s Line 3 Replacement Program, and the level of crude-by-rail activity;
- We anticipate that the IMO regulations regarding high sulphur fuel oil will cause light-heavy crude oil price differentials to widen, although the magnitude and duration of the widening remains uncertain; and
- We expect refining crack spreads will likely continue to fluctuate, adjusting for seasonal trends, and will narrow and widen in tandem with the Brent-WTI differentials. Refining margins will also be impacted by the IMO regulations.

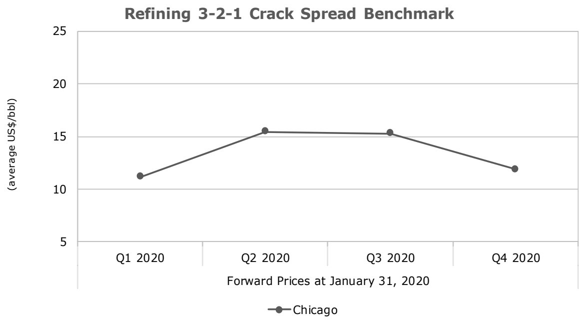
Natural gas and NGLs production associated with our Deep Basin assets provide improved upstream integration for the fuel, solvent and blending requirements at our Oil Sands operations.

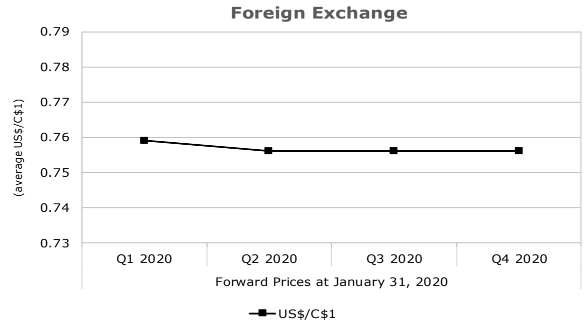




Natural gas prices are anticipated to remain challenged with North American supply continuing to grow as a result of U.S. shale gas drilling and associated natural gas from oil plays. The AECO basis differential is expected to remain lower than NYMEX, reflecting transportation costs.

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 or lower benchmark lending rates relative to each other, and emerging macro-economic factors.





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:

- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets, as well as using 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;
- 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;
- Marketing agreements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners;
- Dynamic storage – our ability to use the significant storage capacity in our oil sands reservoirs provides us flexibility on timing of production and sales of our inventory. We will continue to manage our production well rates in response to pipeline capacity constraints, crude-by-rail export capacity, mandated production curtailments and crude oil price differentials; and
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions related to our exposures.

Key Priorities For Our Five-Year Business Plan

We recently updated and shared our five-year business plan at our Investor Day on October 2, 2019. Our corporate strategy remains focused on maximizing shareholder value through cost leadership and realizing the best margins for our products. The five-year business plan allows for disciplined production growth, subject to improved market access, and provides potential for significant Free Funds Flow generation through 2024 in a WTI price environment of US$45.00 per barrel. In 2020, we expect to be well positioned to increase shareholder returns while we continue to focus on deleveraging, remaining disciplined with our capital investment, improving market access, maintaining cost leadership, and advancing focused technology and innovation to achieve margin improvement and environmental benefits.

Deleveraging and Disciplined Capital Investment

Our commitment to balance sheet strength and capital discipline has allowed us to reduce our Net Debt down to $6.5 billion. Deleveraging continues to be a top priority and we continue to target $5 billion as our longer-term Net Debt target. Improving our financial resilience and flexibility while continuing to deliver safe and reliable operations will continue to be a top priority.

In 2020, we anticipate capital investment to be between $1.3 billion and $1.5 billion. Our oil sands production is expected to range between 390,000 and 410,000 barrels per day for 2020, with the SPA program and our crude-by-rail contracts already in place allowing us to produce from our oil sands facilities on an unconstrained basis in 2020 as we ramp up Christina Lake phase G.

In 2020, we will continue to be disciplined with our capital and focus on further strengthening our balance sheet. The majority of our 2020 capital budget will be directed towards sustaining oil sands production. We also plan to advance high-return projects to sanction-ready status for possible final investment decisions as early as the second half of 2020, conditional on improved market access.

As at December 31, 2019, our Net Debt position was $6.5 billion. Through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $4.4 billion of liquidity as at December 31, 2019.

Over the long-term, we continue to target a Net Debt to Adjusted EBITDA ratio of less than 2.0 times. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure sufficient liquidity through all stages of the economic cycle.

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

Shareholder Returns

While deleveraging remains a top priority for Cenovus, we believe we have built significant financial resilience into our business. Our updated five-year business plan is expected to provide the capacity to fund opportunistic share repurchases and sustainably grow our dividend.

We believe we will have capacity for further dividend increases at a potential growth rate of between five percent and 10 percent annually, even in a WTI price environment of US$45.00 per barrel.

Market Access

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

Cost Leadership

Over the past four years, we have achieved significant improvements in our operating and sustaining capital costs. In 2020, 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.

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 activities 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, 2019 by independent qualified reserves evaluators, based on the COGE Handbook and in compliance with the requirements of NI 51-101. Estimates are presented using an average of three IQREs January 1, 2020 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, 2019.

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", "continuing", "could", "drive", "expect", "estimate", "focus", "forecast", "forward", "future", "guide", "guidance", "may", "outlook", "plan", "position", "potential", "priority", "projection", "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; focus on integrating ESG considerations into our business plan; desire to realize the best margins for our products; potential for significant Free Funds Flow generation through 2024 in a WTI price environment of US$45.00 per barrel; plans to maintain and demonstrate financial discipline while balancing growth and shareholder return; our targeted five percent to 10 percent annual dividend growth; our willingness to consider opportunistic share repurchases, including supporting a potential sale of ConocoPhillips' ownership of our common shares; continuing to advance our operational performance and upholding our trusted reputation; expected timing for oil sands expansion phases and associated expected production capacities; expected production on unconstrained basis; projections for 2020 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 2020 guidance estimates; expected future production, including the timing, stability or growth thereof; the impact of the Government of Alberta's mandatory production curtailment; our ability to take steps to partially mitigate against wider WTI and WCS price differentials; our expectation that our capital investment and any cash dividends for 2020 will be funded from internally generated cash flows and cash balance on hand; expected reserves; capacities, including for projects, transportation and refining; impact on alignment of transportation and storage commitments and production growth; 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 2020; 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 investment, use and development of technology and equipment and associated future outcomes; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future results; planned capital expenditures; 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, but are not limited to: 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 2020 guidance, available at cenovus.com; bottom of the cycle commodity prices of about US$45/bbl WTI and C$44/bbl WCS; 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; opportunities to repurchase shares for cancellation at prices acceptable to us; cash flows and cash balances on hand being sufficient to fund capital investments and dividends, including any increase thereto; 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 continue to maintain a relatively narrow 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; our ability to produce from our Oil Sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; accounting estimates and judgments; future use and development of technology and associated expected future results; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and within the timelines we expect; forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized WCS and WCS prices used to calculate the contingent payment to ConocoPhillips; our ability to access and implement all technology and equipment necessary to achieve expected future results and that such results are realized; 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.

2020 guidance, as updated December 9, 2019, assumes: Brent prices of US$60.00/bbl, WTI prices of US$55.00/bbl; WCS of US$37.50/bbl; AECO natural gas prices of $1.80/Mcf; Chicago 3-2-1 crack spread of US$16.00/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, but are not limited to: 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; unexpected consequences related to the Government of Alberta's mandatory production curtailment; the Government of Alberta may extend mandatory production curtailment beyond when takeaway capacity constraints have been sufficiently relieved; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates regarding commodity prices, currency and interest rates; lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; accuracy of our share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks, exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; our ability to maintain desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including potential dividend increases and 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; cost escalations, including inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes and increased insurance deductibles or premiums; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation and litigation related thereto; 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 equipment and its application to our business, including potential cyberattacks; risks associated with climate change and our assumptions relating thereto; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against us.

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

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

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbls/d	thousand barrels per day	MMcf	million cubic feet
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		

DEFINITIONS

Scope 1 emissions are direct emissions from owned or operated facilities. Cenovus accounts for emissions on a gross operatorship basis. This includes fuel combustion, venting, flaring and fugitive emissions. It does not include emissions from the 50% non-operated ownership in the company's refineries or emissions from non-operated Deep Basin assets.

Scope 2 emissions are indirect emissions from the generation of purchased energy for the company's operated facilities. For Cenovus, this is limited to electricity imports.

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, 2019 ($ millions)	Per Consolidated Financial Statements: Oil Sands[(1)]	Per Consolidated Financial Statements: Deep Basin[(1)]	Per Consolidated Financial Statements: Continuing Operations	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Internal Usage[(2)]	Adjustments: Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	**10,838**	**691**	**11,529**	**(4,021)**	**-**	**(222)**	**(64)**	**7,222**
Royalties	**1,143**	**29**	**1,172**	**-**	**-**	**-**	**1**	**1,173**
Transportation and Blending	**5,152**	**82**	**5,234**	**(4,021)**	**-**	**-**	**1**	**1,214**
Operating	**1,039**	**337**	**1,376**	**-**	**-**	**(222)**	**(33)**	**1,121**
Production and Mineral Taxes	**-**	**1**	**1**	**-**	**-**	**-**	**-**	**1**
Netback	**3,504**	**242**	**3,746**	**-**	**-**	**-**	**(33)**	**3,713**
(Gain) Loss on Risk Management	**23**	**-**	**23**	**-**	**-**	**-**	**-**	**23**
Operating Margin	**3,481**	**242**	**3,723**	**-**	**-**	**-**	**(33)**	**3,690**

Year Ended December 31, 2018 ($ millions) [(3)]	Per Consolidated Financial Statements: Oil Sands[(1)]	Per Consolidated Financial Statements: Deep Basin[(1)]	Per Consolidated Financial Statements: Continuing Operations	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Internal Usage[(2)]	Adjustments: 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) [(3)]	Per Consolidated Financial Statements: Oil Sands[(1)]	Per Consolidated Financial Statements: Deep Basin[(1)]	Per Consolidated Financial Statements: Continuing Operations	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Internal Usage[(2)]	Adjustments: 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

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

Three Months Ended December 31, 2019 ($ millions)	Per Interim Consolidated Financial Statements: Oil Sands[(4)]	Per Interim Consolidated Financial Statements: Deep Basin[(4)]	Per Interim Consolidated Financial Statements: Continuing Operations	Adjustments: Condensate	Adjustments: Inventory	Adjustments: Internal Usage[(5)]	Adjustments: Other	Basis of Netback Calculation: Continuing Operations
Gross Sales	**2,659**	**190**	**2,849**	**(1,060)**	**-**	**(82)**	**(13)**	**1,694**
Royalties	**316**	**9**	**325**	**-**	**-**	**-**	**1**	**326**
Transportation and Blending	**1,416**	**20**	**1,436**	**(1,060)**	**-**	**-**	**1**	**377**
Operating	**268**	**80**	**348**	**-**	**-**	**(82)**	**(6)**	**260**
Production and Mineral Taxes	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Netback	**659**	**81**	**740**	**-**	**-**	**-**	**(9)**	**731**
(Gain) Loss on Risk Management	**(15)**	**-**	**(15)**	**-**	**-**	**-**	**-**	**(15)**
Operating Margin	**674**	**81**	**755**	**-**	**-**	**-**	**(9)**	**746**

(4) Found in Note 1 of the Interim Consolidated Financial Statements.
(5) 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) (3)	Per Interim 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	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)

(1) Found in Note 1 of the Interim Consolidated Financial Statements.
(2) Represents natural gas volumes produced by the Deep Basin segment used for internal consumption by the Oil Sands segment.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the Critical Accounting Judgments, Estimation Uncertainties and Accounting Polices section in this MD&A.

Oil Sands

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments Condensate	Inventory	Other	Per Consolidated Financial Statements(4) Total Oil Sands
Gross Sales	3,295	3,511	6,806	-	4,021	-	11	10,838
Royalties	486	650	1,136	-	-	-	7	1,143
Transportation and Blending	674	458	1,132	-	4,021	-	(1)	5,152
Operating	526	505	1,031	-	-	-	8	1,039
Netback	1,609	1,898	3,507	-	-	-	(3)	3,504
(Gain) Loss on Risk Management	10	13	23	-	-	-	-	23
Operating Margin	1,599	1,885	3,484	-	-	-	(3)	3,481

Year Ended December 31, 2018 ($ millions) (5)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments Condensate	Inventory	Other	Per Consolidated Financial Statements (4) 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) (5)	Basis of Netback Calculation Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Adjustments Condensate	Inventory	Other	Per Consolidated Financial Statements (4) 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

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

Three Months Ended December 31, 2019 ($ 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	731	866	1,597	-	1,060	-	2	2,659
Royalties	130	179	309	-	-	-	7	316
Transportation and Blending	207	150	357	-	1,060	-	(1)	1,416
Operating	132	136	268	-	-	-	-	268
Netback	262	401	663	-	-	-	(4)	659
(Gain) Loss on Risk Management	(5)	(10)	(15)	-	-	-	-	(15)
Operating Margin	267	411	678	-	-	-	(4)	674

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

Three Months Ended December 31, 2018 ($ millions) [2]	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)

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

Deep Basin

Year Ended December 31, 2019 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[4]	Per Consolidated Financial Statements[3] Total Deep Basin
Gross Sales	638	53	691
Royalties	29	-	29
Transportation and Blending	82	-	82
Operating	312	25	337
Production and Mineral Taxes	1	-	1
Netback	214	28	242
(Gain) Loss on Risk Management	-	-	-
Operating Margin	214	28	242

Year Ended December 31, 2018 ($ millions) [5]	Basis of Netback Calculation Total	Adjustments Other[4]	Per Consolidated Financial Statements[3] 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) [5]	Basis of Netback Calculation Total	Adjustments Other[4]	Per Consolidated Financial Statements[3] 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

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

Three Months Ended December 31, 2019 ($ millions)	Basis of Netback Calculation Total	Adjustments Other[(2)]	Per Interim Consolidated Financial Statements[(1)] Total Deep Basin
Gross Sales	**179**	**11**	**190**
Royalties	**9**	**-**	**9**
Transportation and Blending	**20**	**-**	**20**
Operating	**74**	**6**	**80**
Production and Mineral Taxes	**-**	**-**	**-**
Netback	**76**	**5**	**81**
(Gain) Loss on Risk Management	**-**	**-**	**-**
Operating Margin	**76**	**5**	**81**

Three Months Ended December 31, 2018 ($ millions) [(3)]	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
Netback	53	9	62
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	9	62

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

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

Sales Volumes

(barrels per day, unless otherwise stated)	Three Months Ended December 31, 2019	Three Months Ended December 31, 2018	Year Ended December 31 2019	Year Ended December 31 2018	Year Ended December 31 2017
Oil Sands					
Foster Creek	**153,797**	143,928	**157,770**	162,685	121,806
Christina Lake	**207,399**	186,530	**188,910**	204,016	161,514
Total Oil Sands Crude Oil	**361,196**	330,458	**346,680**	366,701	283,320
Natural Gas (MMcf per day)	**-**	-	**-**	1	10
Total Oil Sands (BOE per day)	**361,196**	330,458	**346,680**	366,905	284,984
Deep Basin					
Total Liquids	**26,197**	28,111	**26,673**	32,454	20,850
Natural Gas (MMcf per day)	**403**	469	**424**	527	316
Total Deep Basin (BOE per day)	**93,317**	106,232	**97,423**	120,258	73,492
Less: Internal Consumption [(4)] (MMcf per day)	**(336)**	(310)	**(320)**	(306)	-
Sales From Continuing Operations [(4)] (BOE per day)	**398,457**	385,023	**390,813**	436,163	358,476

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