MANAGEMENT'S DISCUSSION AND ANALYSIS
FOR THE YEAR ENDED DECEMBER 31, 2017

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", mean Cenovus Energy Inc., the subsidiaries of, and partnership interests held by, Cenovus Energy Inc. and its subsidiaries) dated February 14, 2018, should be read in conjunction with December 31, 2017 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 14, 2018, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. The information in this MD&A, as it relates to our operations for 2017, reflects the closing of the Acquisition (as defined in this MD&A) on May 17, 2017. 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 14, 2018. Additional information about Cenovus, including our quarterly and annual reports, the Annual Information Form ("AIF") and Form 40-F, is available on SEDAR at sedar.com, on EDGAR at sec.gov, and on our website at cenovus.com. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Basis of Presentation

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

Non-GAAP Measures and Additional Subtotals

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS, such as Netbacks, Adjusted Funds Flow, Operating Earnings, Free Funds Flow, Debt, Net Debt, Capitalization and Adjusted Earnings Before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. In addition, Operating Margin is considered an additional subtotal found in Notes 1 and 11 of our Consolidated Financial Statements. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

The definition and reconciliation, if applicable, of each non-GAAP measure or additional subtotal is presented in the Operating Results, Financial Results, Liquidity and Capital Resources, or Advisory sections of this MD&A.

OVERVIEW OF CENOVUS

We are a Canadian integrated oil company headquartered in Calgary, Alberta, with our shares listed on the Toronto and New York stock exchanges. On December 31, 2017, we had an enterprise value of approximately $24 billion. We are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in western Canada. We also conduct marketing activities and have refining operations in the United States ("U.S."). Our average crude oil and NGLs (collectively, "liquids") production in 2017 was 360,704 barrels per day, our average natural gas production was 659 MMcf per day, and our total production was 470,490 BOE per day. The refining operations processed an average of 442,000 gross barrels per day of crude oil feedstock into an average of 470,000 gross barrels per day of refined products.

Year in Review

2017 was a year of significant change for Cenovus, where we gained full ownership of our oil sands assets, acquired an additional core operating area in the Deep Basin and divested the majority of our legacy Conventional assets. On May 17, 2017, we acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") their 50 percent interest in the FCCL Partnership ("FCCL"), and the majority of ConocoPhillips' western Canadian conventional assets in the Deep Basin in Alberta and British Columbia for total consideration of $17.9 billion ("the Acquisition").

The Acquisition effectively doubled our oil sands production and proved bitumen reserves. In addition, we acquired more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia (collectively, the "Deep Basin Assets"). The Deep Basin Assets are expected to provide short-cycle development opportunities with high-return potential that complement our long-cycle oil sands investments.

The purchase consideration included US$10.6 billion in cash, before adjustments, and 208 million Cenovus common shares. The cash portion of the consideration was funded through a combination of cash on hand, a draw on our existing committed credit facility, an offering of senior unsecured notes (US$2.9 billion), a committed asset-sale bridge credit facility ($3.6 billion) ("Bridge Facility"), and a bought-deal common share offering ($3.0 billion).

In the second half of 2017, we sold the majority of our legacy Conventional crude oil and natural gas assets for aggregate gross cash proceeds of approximately $3.2 billion. The net proceeds and cash on hand were used to fully repay and retire the Bridge Facility. The sale of Suffield, our remaining legacy Conventional segment asset, closed on January 5, 2018 for gross proceeds of $512 million. In aggregate, gross proceeds for all legacy Conventional crude oil and natural gas assets divested was $3.7 billion, before closing adjustments, and resulted in a before-tax gain on discontinuance of approximately $1.6 billion, of which $1.3 billion was recorded in 2017.

In December 2017, we also commenced marketing for sale certain non-core assets located in the East and West Clearwater areas of the Deep Basin, representing approximately 15,000 BOE per day of production, to further streamline our portfolio and deleverage our balance sheet.

Over the course of 2017, Cenovus has transitioned its asset base and strategy to support focused development in the oil sands and Deep Basin, providing opportunities for disciplined growth and long-term cash flow generation. At the same time, investor concern about the Acquisition, volatile commodity prices and a number of other factors contributed to a more than 40 percent decline in our share price. Over the last few months, Cenovus has made considerable progress in reducing debt and is taking steps to right-size the Company for the current environment. Effective November 6, 2017, Alex Pourbaix was appointed Cenovus's President and Chief Executive Officer, and he subsequently announced changes to the senior leadership team in December 2017.

Cenovus's 2018 budget was announced in December, with total capital expenditures expected to be between $1.5 billion and $1.7 billion. This budget reflects Cenovus's focus on capital discipline, cost reductions and deleveraging.

Our Strategy

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

Our Key Strategic Differentiators

Premium Asset Quality

Cenovus has a deep portfolio of premium-quality oil sands, natural gas and NGLs assets that we believe provide us with significant cost and environmental performance advantages. Our in-situ oil sands projects and Deep Basin Assets in western Canada offer long and short-cycle opportunities that provide the capital investment flexibility to position us to deliver value growth at various points of the price cycle. In addition to our exploration and production assets, we have complementary interests in refineries and product transportation infrastructure.

Executional Excellence

Our team is committed to delivering on our business plan in a safe, disciplined and responsible manner and continuously improving our performance to help manage risk and optimize returns. We use a manufacturing approach to support consistent performance and enhance reliability. This involves applying standardized and repeatable designs and processes to the construction and operation of our facilities to reduce costs and improve efficiencies at all project stages. We strive to execute our work in an agile manner with a focus on using our resources effectively.

Value-Added Integration

Our integrated business approach helps provide stability to our cash flows and maximize value for the oil and natural gas we produce. Having ownership in oil refineries positions us to capture the full value chain from production to high-quality end products like transportation fuels. In addition, our pipeline commitments, crude-by-rail loading facility and product marketing activities assist us to obtain global pricing for our oil. As a consumer of natural gas at our oil sands facilities and refineries, our natural gas production acts as an economic hedge to help manage price volatility. In addition, our cogeneration plants efficiently provide power for our oil sands facilities with the added value of excess electricity being sold to the Alberta electricity grid.

Focused Innovation

We focus our innovation efforts on accelerating the adoption of technology solutions and methods of operating to enhance safety, reduce costs, improve margins and lower emissions. We expect innovation at Cenovus to mean significant improvements and game-changing developments that are implemented to generate value. We aim to complement our internal technology development efforts with external collaboration that will leverage our technology spend.

Trusted Reputation

We are a responsible, progressive company that is committed to providing a safe and healthy workplace, building strong external relationships, minimizing our environmental footprint and being a part of a lower carbon future. Our actions are intended to support our trusted reputation and enable us to attract and retain top-quality staff and to engage with and be respected by our stakeholders: investors, the communities in which we operate, environmental groups, governments, Aboriginal people, media, project partners and the general public.

We measure our performance through a scorecard that reflects our financial, operational, safety, environmental and organizational health goals.

Our Operations

Oil Sands

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

	2017	
($ millions)	**Crude Oil**	**Natural Gas**
Operating Margin	**2,231**	**1**
Capital Investment	**969**	**4**
Operating Margin Net of Related Capital Investment	**1,262**	**(3)**

Deep Basin

Our Deep Basin Assets include approximately three million net acres of land rich in natural gas, condensate and other NGLs, and light and medium oil. The assets are located primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas of British Columbia and Alberta, and include interests in numerous natural gas processing facilities. The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development and provide an economic hedge for the natural gas required as a fuel source at both our oil sands and refining operations.

($ millions)	**May 17 – December 31, 2017**
Operating Margin	**207**
Capital Investment	**225**
Operating Margin Net of Related Capital Investment	**(18)**

Conventional

All references to our legacy Conventional segment are accounted for as a discontinued operation.

In late 2017, we sold the majority of our legacy Conventional crude oil and natural gas assets for gross cash proceeds totaling approximately $3.2 billion, resulting in a net before-tax gain on discontinuance of approximately $1.3 billion. The sale of our remaining Conventional segment asset, Suffield, closed on January 5, 2018 for gross proceeds of $512 million and resulted in a before-tax gain on sale of approximately $350 million.

The Conventional segment produced crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide (“CO_2”) enhanced oil recovery project at Weyburn and tight oil opportunities in the Palliser block in southern Alberta.

	2017	
($ millions)	Liquids	Natural Gas
Operating Margin	360	124
Capital Investment	195	11
Operating Margin Net of Related Capital Investment	**165**	**113**

Refining and Marketing

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

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

($ millions)	2017
Operating Margin	598
Capital Investment	180
Operating Margin Net of Related Capital Investment	**418**

2017 HIGHLIGHTS

In 2017, we completed the Acquisition which gave us full ownership of our oil sands operations and provided an additional core operating area with the Deep Basin Assets.

Including the Suffield divestiture which closed on January 5, 2018, all of our legacy Conventional oil and gas assets have been sold for combined gross cash proceeds of $3.7 billion. Gross proceeds received prior to December 31, 2017 of $3.2 billion, combined with cash on hand, were used to fully repay and retire the $3.6 billion Bridge Facility that was drawn to help fund the Acquisition.

Crude oil prices continued to be volatile throughout the year. West Texas Intermediate (“WTI”) benchmark crude price ranged from a high of US$60.42 per barrel to a low of US$42.53 per barrel and averaged 18 percent higher compared with 2016. Western Canadian Select (“WCS”), a blended heavy oil benchmark, ranged from a high of US$44.79 per barrel to a low of US$29.56 per barrel, while averaging 32 percent higher in 2017 compared to 2016. In addition, natural gas prices were very volatile, ranging from a high of $3.75 per Mcf to a low of $1.07 per Mcf; however, still averaging 16 percent higher than 2016.

In 2017, we:

- Produced 470,490 BOE per day, a 73 percent increase from 2016;
- Earned an average companywide Netback from continuing operations of $20.89 per BOE, before realized hedging, an increase of 78 percent from 2016;
- Generated upstream operating margin, excluding the Conventional segment, of $2,394 million compared with $877 million in 2016 primarily due to the Acquisition, a rise in sales volumes and higher liquids sales prices;
- Achieved cash from operating activities and Adjusted Funds Flow of $3,059 million and $2,914 million, respectively, increasing significantly from 2016;
- Recorded a $275 million tax recovery as a result of the U.S. federal corporate income tax rate change announced in 2017;
- Recorded Net Earnings from continuing operations of $2,268 million (2016 – Net Loss from continuing operations of $459 million);
- Invested $1,661 million in capital which allowed us to generate Free Funds Flow of $1,253 million, a threefold increase from $397 million in 2016;

- Divested of the majority of our legacy Conventional crude oil and natural gas assets, recognizing a before-tax gain of $1.3 billion in discontinued operations;
- Announced the appointment of Alex Pourbaix as President and Chief Executive Officer in November, and announced changes to the senior leadership team in December;
- Re-evaluated our oil sands Exploration & Evaluation ("E&E") projects in line with our current business plans. As a result, we wrote off $887 million in the fourth quarter as exploration expense; and
- Announced our 2018 budget in December, focusing on capital discipline, cost reductions and deleveraging.

OPERATING RESULTS

Our upstream assets continued to perform well in 2017. Total production increased primarily due to the Acquisition, slightly offset by the disposition of legacy Conventional assets late in the year.

Production Volumes

	2017	**Percent Change**	2016	Percent Change	2015
Continuing Operations					
Liquids (barrels per day)					
Oil Sands					
Foster Creek	**124,752**	**78%**	70,244	7%	65,345
Christina Lake	**167,727**	**111%**	79,449	6%	74,975
	292,479	**95%**	149,693	7%	140,320
Deep Basin					
Light and Medium Oil	**3,922**	**-%**	-	-%	-
NGLs	**16,928**	**-%**	-	-%	-
	20,850	**-%**	-	-%	-
Liquids Production (barrels per day)	**313,329**	**109%**	149,693	7%	140,320
Natural Gas (MMcf per day)					
Oil Sands	**10**	**(41)%**	17	(11)%	19
Deep Basin	**316**	**-%**	-	-%	-
	326	**1,818%**	17	(11)%	19
Conventional Production (BOE per day)	**-**	**-%**	-	-%	4,163
Production From Continuing Operations (BOE per day)	**367,635**	**141%**	152,527	3%	147,701
Discontinued Operations (Conventional)					
Liquids (barrels per day)					
Heavy Oil	**21,478**	**(26)%**	29,185	(15)%	34,256
Light and Medium Oil	**24,824**	**(4)%**	25,915	(10)%	28,675
NGLs	**1,073**	**1%**	1,065	(7)%	1,149
	47,375	**(16)%**	56,165	(12)%	64,080
Natural Gas (MMcf per day)	**333**	**(12)%**	377	(8)%	412
Production From Discontinued Operations (BOE per day)	**102,855**	**(14)%**	118,998	(10)%	132,746
Total Production (BOE per day)	**470,490**	**73%**	271,525	(3)%	280,447

In 2017, Oil Sands production increased primarily as a result of the Acquisition. Incremental production at Foster Creek and Christina Lake from May 17, 2017, the closing date of the Acquisition, until December 31, 2017 was 76,748 barrels per day and 102,945 barrels per day, respectively. Foster Creek also had incremental production volumes related to the phase G expansion, partially offset by reduced volumes as a result of temporary treating issues and a 20-day planned plant turnaround. The phase F expansion at Christina Lake contributed incremental production volumes.

Total production in the Deep Basin averaged 117,138 BOE per day for the period of May 17, 2017 to December 31, 2017. Incremental volumes due to the drilling and completion of horizontal production wells in the second half of the year was partially offset by downtime associated with third-party pipeline and facility outages.

Prior to the dispositions, our Conventional liquids production was lower than in 2016 primarily due to expected natural declines partially offset by new production from our tight oil drilling program in the first half of 2017, before growth capital was reduced as a result of the decision to divest the Palliser asset. Our Conventional natural gas production decreased in 2017, relative to the same period in 2016 due to expected natural declines.

Oil and Gas Reserves

Based on our reserves report prepared by independent qualified reserves evaluators ("IQREs"), our proved bitumen reserves increased 103 percent to approximately 4.75 billion barrels and our proved plus probable bitumen reserves increased 92 percent to approximately 6.38 billion barrels. Our Deep Basin proved reserves were 410 MMBOE and our proved plus probable reserves were 660 MMBOE.

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

Netbacks From Continuing Operations

Netback is a non-GAAP measure commonly used in the oil and gas industry to assist in measuring operating performance on a per-unit basis, and is defined in the Canadian Oil and Gas Evaluation Handbook. Netbacks reflect our margin on a per-barrel of oil equivalent basis. Netback is defined as gross sales less royalties, transportation and blending, operating expenses and production and mineral taxes divided by sales volumes. Netbacks do not reflect the non-cash writedowns of product inventory until the product is sold. The sales price, transportation and blending costs, and sales volumes exclude the impact of purchased condensate. Condensate is blended with the heavy oil to reduce its thickness in order to transport it to market. Our Netback calculation is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. For a reconciliation of our Netbacks see the Advisory section of this MD&A.

($/BOE)	**2017**	2016	2015
Sales Price	**36.86**	27.37	30.81
Royalties	**2.07**	0.17	0.56
Transportation and Blending	**5.43**	6.51	6.34
Operating Expenses	**8.46**	8.94	9.94
Production and Mineral Taxes	**0.01**	-	0.03
Netback Excluding Realized Risk Management [1]	**20.89**	11.75	13.94
Realized Risk Management Gain (Loss)	**(2.35)**	3.22	7.60
Netback Including Realized Risk Management [1]	**18.54**	14.97	21.54

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

Our average Netback improved primarily due to higher liquids sales prices, partially offset by increased royalties and the strengthening of the Canadian dollar relative to the U.S. dollar. The strengthening of the Canadian dollar compared with 2016 had a negative impact on our sales price of approximately $0.78 per BOE.

Refining and Marketing

Crude oil runs and refined product output in 2017 remained consistent compared with 2016. The planned and unplanned maintenance at both Refineries in 2017 had a similar impact on crude oil runs and refined product output as the planned and unplanned maintenance in 2016.

	2017	**Percent Change**	2016	Percent Change	2015
Crude Oil Runs [1] (Mbbls/d)	**442**	**-%**	444	6%	419
Heavy Crude Oil [1]	**202**	**(13)%**	233	17%	200
Refined Product [1] (Mbbls/d)	**470**	**-%**	471	6%	444
Crude Utilization [1] (percent)	**96**	**(1)%**	97	6%	91

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

In 2017, Operating Margin from our Refining and Marketing segment increased 73 percent compared with 2016 due to higher average market crack spreads and increased margins on the sale of our secondary products due to higher realized pricing. These increases were partially offset by narrowing heavy crude oil differentials, which increase crude input costs to the refinery, and the strengthening of the Canadian dollar relative to the U.S. dollar.

Further information on the changes in our production volumes, items included in our Netbacks and refining results can be found in the Reportable Segments section of this MD&A. Further information on our risk management activities can be found in the Risk Management and Risk Factors section of this MD&A and in the notes to the Consolidated Financial Statements.

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

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

Selected Benchmark Prices and Exchange Rates [(1)]

(US$/bbl, unless otherwise indicated)	**Q4 2017**	Q4 2016	**2017**	**Percent Change**	2016	2015
Crude Oil Prices						
Brent						
Average	**61.54**	51.13	**54.82**	**22%**	45.04	53.64
End of Period	**66.87**	56.82	**66.87**	**18%**	56.82	37.28
WTI						
Average	**55.40**	49.29	**50.95**	**18%**	43.32	48.80
End of Period	**60.42**	53.72	**60.42**	**12%**	53.72	37.04
Average Differential Brent-WTI	**6.14**	1.84	**3.87**	**125%**	1.72	4.84
WCS						
Average	**43.14**	34.97	**38.97**	**32%**	29.48	35.28
Average (C$/bbl)	**54.84**	46.63	**50.56**	**29%**	39.05	45.12
End of Period	**34.93**	38.81	**34.93**	**(10)%**	38.81	24.98
Average Differential WTI-WCS	**12.26**	14.32	**11.98**	**(13)%**	13.84	13.52
Condensate (C5 @ Edmonton)						
Average [(2)]	**57.97**	48.33	**51.57**	**21%**	42.47	47.36
Average Differential WTI-Condensate (Premium)/Discount	**(2.57)**	0.96	**(0.62)**	**(173)%**	0.85	1.44
Average Differential WCS-Condensate (Premium)/Discount	**(14.83)**	(13.36)	**(12.60)**	**(3)%**	(12.99)	(12.08)
Mixed Sweet Blend ("MSW" @ Edmonton)						
Average [(3)]	**54.26**	46.18	**48.49**	**21%**	40.11	45.32
End of Period	**53.03**	51.26	**53.03**	**3%**	51.26	34.98
Average Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**74.36**	59.46	**66.95**	**19%**	56.24	67.68
Chicago Ultra-low Sulphur Diesel ("ULSD")	**80.58**	61.50	**69.09**	**23%**	56.33	68.12
Refining Margin: Average 3-2-1 Crack Spreads [(4)]						
Chicago	**21.09**	10.96	**16.77**	**28%**	13.07	19.11
Average Natural Gas Prices						
AECO (C$/Mcf) [(5)]	**1.96**	2.81	**2.43**	**16%**	2.09	2.77
NYMEX (US$/Mcf)	**2.93**	2.98	**3.11**	**26%**	2.46	2.66
Basis Differential NYMEX-AECO (US$/Mcf)	**1.40**	0.86	**1.26**	**42%**	0.89	0.49
Foreign Exchange Rate (US$ per C$1)						
Average	**0.787**	0.750	**0.771**	**2%**	0.755	0.782

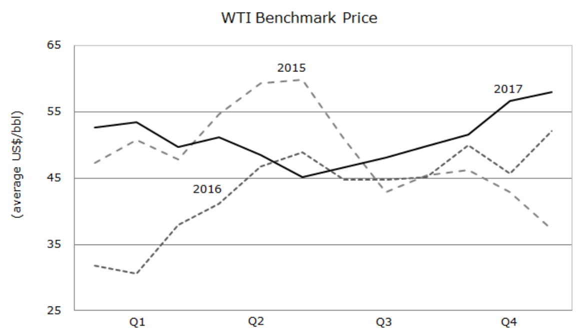
(1) *These benchmark prices are not our realized sales prices. For our average realized sales prices and realized risk management results, refer to the Netbacks tables in the Operating Results, Reportable Segments and Discontinued Operations sections of this MD&A.*
(2) *The average Canadian dollar condensate benchmark price for 2017 was $66.89 per barrel (2016 – $56.25 per barrel; 2015 – $60.56 per barrel); fourth quarter average condensate benchmark price was $73.66 per barrel (2016 – $64.44 per barrel).*
(3) *The average Canadian dollar MSW benchmark price for 2017 was $62.89 per barrel (2016 – $53.13 per barrel; 2015 – $57.95 per barrel); fourth quarter average Canadian dollar MSW benchmark price was $68.95 per barrel (2016 – $61.57 per barrel).*
(4) *The average 3-2-1 Crack Spread is an indicator of the refining margin and is valued on a last in, first out accounting basis.*
(5) *Alberta Energy Company ("AECO") natural gas.*

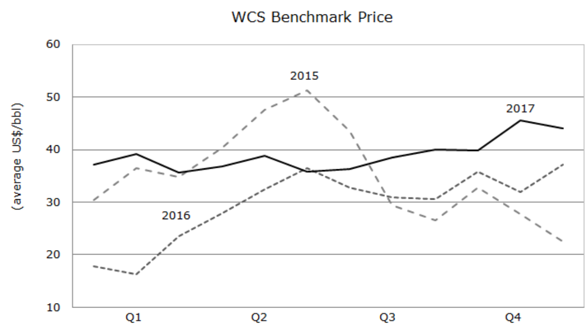
Crude Oil Benchmarks

The average Brent, WTI and WCS benchmark prices improved in 2017. Compliance with the production cuts outlined in the fourth quarter of 2016 by the Organization of Petroleum Exporting Countries ("OPEC") led to widespread market expectations of an accelerated return to normal inventory levels. However, without supporting supply and demand drivers, prices continued to be volatile in 2017 as growing supply from the U.S., unstable supply from Libya and Nigeria, severe weather related incidents, and strong global demand resulted in varying expectations on the pace of crude oil and refined product inventory draws.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices and its Canadian dollar equivalent is the basis for determining royalties for a number of our crude oil properties. In 2017, WTI benchmark prices weakened relative to Brent compared with 2016 due to growing U.S. crude oil supply and refinery disruptions from hurricanes in the U.S. Gulf Coast resulting in increased crude oil inventories.

WCS is blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The average WTI-WCS differential narrowed in 2017 compared with 2016. WCS strengthened relative to WTI due to a temporary decrease in supply of blended heavy oil in Alberta and OPEC's compliance with production cuts reducing global heavy oil supply.





Blending condensate with bitumen and heavy oil enables our production to be transported through pipelines. Our blending ratios in 2017 ranged from approximately 10 percent to 33 percent. The WCS-Condensate differential is an important benchmark as a narrower differential generally results in an increase in the recovery of condensate costs when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by U.S. Gulf Coast condensate prices plus the cost to transport the condensate to Edmonton.

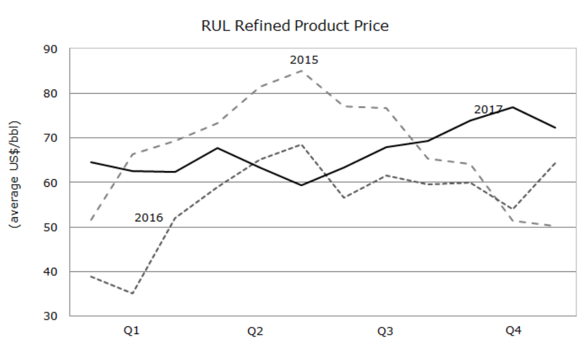
The average WTI-Condensate differential changed by US$1.47 per barrel, with condensate being sold at a premium to WTI in 2017 as compared with being sold at a discount in 2016. This change in benchmark pricing resulted from incremental demand for diluent due to a rise in Alberta heavy oil production, and minimal spare capacity on pipelines which increased the cost of transporting condensate to Edmonton.

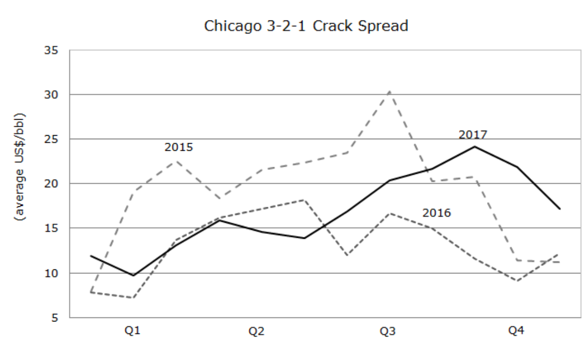
MSW is an Alberta based light sweet crude oil benchmark that is representative of Canadian conventional production, comparable to the crude oil produced by our Deep Basin Assets. The average MSW benchmark price improved in 2017 compared with 2016, consistent with the general increase in average crude oil benchmark prices.

Refining Benchmarks

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

Average Chicago refined product prices increased in 2017 primarily due to strong refined product demand and severe weather related events that impacted the refined product supply output of U.S. Gulf Coast refineries. Average Chicago 3-2-1 crack spreads rose in 2017 compared with 2016 due to the wider Brent-WTI differential reflecting product prices trending with global crude oil prices, significant regional refinery maintenance causing product shortages and strong refined product demand. 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 and NYMEX natural gas prices rose compared with 2016. Natural gas prices strengthened as North American inventory levels declined due to lower production and stronger demand. Production decreased as a result of reduced drilling programs while demand increased from additional capacity to export North American natural gas to foreign markets. In addition, natural gas prices in 2016 were negatively impacted by an exceptionally warm winter that resulted in poor heating demand and record-high seasonal North American natural gas storage levels.

Foreign Exchange Benchmark

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, natural gas and refined products are determined by reference to U.S. benchmark prices. 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, our reported results are higher. In addition to our revenues being denominated in U.S. dollars, our long-term debt is also U.S. dollar denominated. In periods of a strengthening Canadian dollar, our U.S. dollar debt gives rise to unrealized foreign exchange gains when translated to Canadian dollars.

In 2017, the Canadian dollar strengthened relative to the U.S. dollar, which had a negative impact of approximately $360 million on our revenues, excluding our Conventional segment. The Canadian dollar as at December 31, 2017 compared with December 31, 2016 was stronger relative to the U.S. dollar, resulting in $665 million of unrealized foreign exchange gains on the translation of our U.S. dollar debt.

FINANCIAL RESULTS

Selected Consolidated Financial Results

The Acquisition and improvements in commodity prices, as referred to above, were the primary drivers of our financial results in 2017. The following key performance measures are discussed in more detail within this MD&A.

($ millions, except per share amounts)	**2017**	**Percent Change**	2016	Percent Change	2015
Revenues	**17,043**	**55%**	11,006	(5)%	11,529
Operating Margin (1)					
From Continuing Operations	**2,992**	**145%**	1,223	(18)%	1,499
Total Operating Margin	**3,483**	**97%**	1,767	(28)%	2,439
Cash From Operating Activities					
From Continuing Operations	**2,611**	**513%**	426	(39)%	696
Total Cash From Operating Activities	**3,059**	**255%**	861	(42)%	1,474
Adjusted Funds Flow (2)					
From Continuing Operations	**2,447**	**154%**	965	8%	896
Total Adjusted Funds Flow	**2,914**	**105%**	1,423	(16)%	1,691
Operating Earnings (Loss) (2)					
From Continuing Operations	**(34)**	**88%**	(291)	(172)%	(107)
Per Share – Diluted ($)	**(0.03)**	**91%**	(0.35)	(169)%	(0.13)
Total Operating Earnings (Loss)	**126**	**(133)%**	(377)	6%	(403)
Per Share – Diluted ($)	**0.11**	**(124)%**	(0.45)	8%	(0.49)
Net Earnings (Loss)					
From Continuing Operations	**2,268**	**(594)%**	(459)	(150)%	914
Per Share – Basic and Diluted ($)	**2.06**	**(475)%**	(0.55)	(149)%	1.12
Total Net Earnings (Loss)	**3,366**	**(718)%**	(545)	(188)%	618
Per Share – Basic and Diluted ($)	**3.05**	**(569)%**	(0.65)	(187)%	0.75
Total Assets	**40,933**	**62%**	25,258	(2)%	25,791
Total Long-Term Financial Liabilities (3)	**9,717**	**52%**	6,373	(2)%	6,552
Capital Investment (4)					
From Continuing Operations	**1,455**	**70%**	855	(42)%	1,470
Total Capital Investment	**1,661**	**62%**	1,026	(40)%	1,714
Dividends (5)					
Cash Dividends	**225**	**36%**	166	(69)%	528
Per Share ($)	**0.20**	**-%**	0.20	(77)%	0.8524

(1) Additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Includes Long-Term Debt, Risk Management, Contingent Payment Liabilities and other financial liabilities included within Other Liabilities on the Consolidated Balance Sheets.
(4) Includes expenditures on Property, Plant and Equipment ("PP&E"), E&E assets, and assets held for sale.
(5) Dividends issued in shares from treasury for 2017 were $nil (2016 – $nil; 2015 – $182 million).

Revenues

($ millions)	2017 vs. 2016	2016 vs. 2015
Revenues, Comparative Year	**11,006**	11,529
Increase (Decrease) due to:		
Oil Sands	**4,212**	(81)
Deep Basin	**514**	-
Refining and Marketing	**1,413**	(366)
Corporate and Eliminations	**(102)**	(76)
Revenues, End of Year	**17,043**	11,006

Upstream revenues from continuing operations increased significantly in 2017 compared with 2016. The rise was primarily related to the Acquisition, incremental sales volumes from our oil sands expansion phases, and higher commodity prices. These increases were partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar and higher royalties.

In 2017, Refining and Marketing revenues increased 17 percent compared with 2016. Refining revenues increased primarily due to higher refined product pricing, consistent with the rise in average Chicago refined product benchmark prices, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. Revenues from third-party crude oil and natural gas sales undertaken by our marketing group increased slightly in 2017 compared with 2016 due to higher crude oil prices and natural gas volumes sold, partially offset by a decline in crude oil volumes and natural gas prices.

Corporate and Eliminations revenues relate to sales and operating revenues between segments and are recorded at transfer prices based on current market prices.

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

Operating Margin

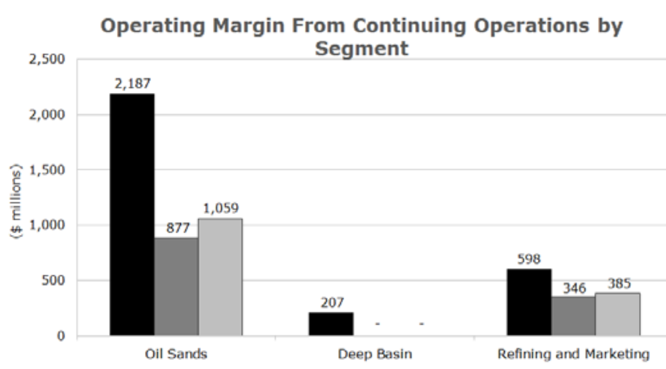
Operating Margin is an additional subtotal found in Notes 1 and 11 of the Consolidated Financial Statements and is used to provide a consistent measure of the cash generating performance of our assets for comparability of our underlying financial performance between periods. Operating Margin is defined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

($ millions)	2017	2016	2015 (1)
Revenues	**17,498**	11,359	11,866
(Add) Deduct:			
Purchased Product	**8,476**	7,325	7,709
Transportation and Blending	**3,760**	1,721	1,816
Operating Expenses	**1,956**	1,243	1,288
Production and Mineral Taxes	**1**	-	1
Realized (Gain) Loss on Risk Management Activities	**313**	(153)	(447)
Operating Margin From Continuing Operations	**2,992**	1,223	1,499
Conventional (Discontinued Operations)	**491**	544	940
Total Operating Margin	**3,483**	1,767	2,439

(1) *2015 Operating Margin From Continuing Operations includes $55 million related to certain legacy Conventional royalty interest assets which were sold in 2015 and has been included in the Corporate and Eliminations Segment.*

Operating Margin from continuing operations increased significantly in 2017 compared with 2016 primarily due to:

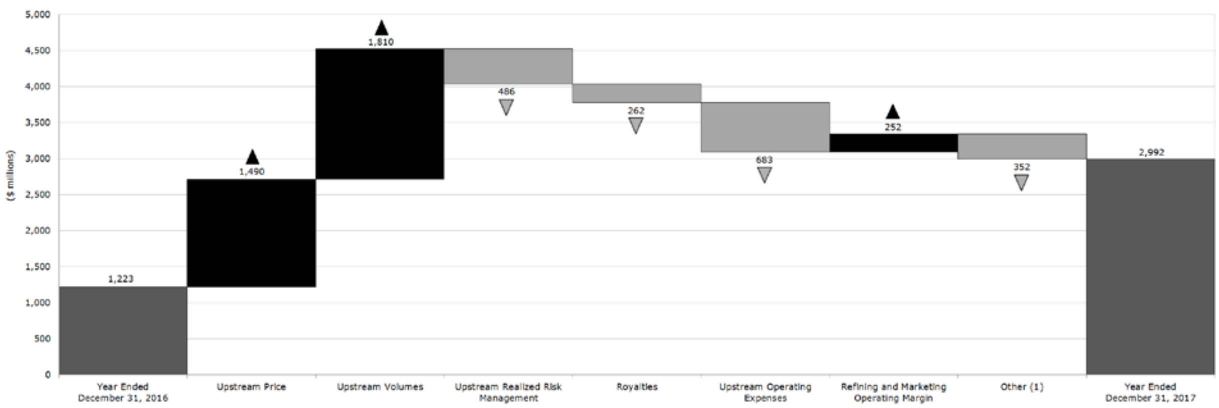
- Increased sales volumes;
- Higher average liquids sales prices; and
- A higher Operating Margin from Refining and Marketing.



These increases in Operating Margin from continuing operations were partially offset by:

- A rise in transportation and blending expenses primarily due to higher condensate prices along with an increase in condensate volumes required for blending our increased oil sands production;
- An increase in upstream operating expenses primarily due to the Acquisition and higher fuel costs related to the increase in natural gas consumption;
- Realized risk management losses of $307 million, compared with gains of $179 million in 2016; and
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), a rise in our liquids sales price and additional sales volumes.

Operating Margin From Continuing Operations Variance



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

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

Cash From Operating Activities and Adjusted Funds Flow

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

Total Cash From Operating Activities and Adjusted Funds Flow

($ millions)	**2017**	2016	2015
Cash From Operating Activities (1)	**3,059**	861	1,474
(Add) Deduct:			
Net Change in Other Assets and Liabilities	**(107)**	(91)	(107)
Net Change in Non-Cash Working Capital	**252**	(471)	(110)
Adjusted Funds Flow (1)	**2,914**	1,423	1,691

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

Cash From Operating Activities and Adjusted Funds Flow increased compared with 2016 due to a higher Operating Margin, as discussed above, and a realized risk management gain on foreign exchange contracts due to hedging activity undertaken to support the Acquisition. These increases were partially offset by a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition and an increase in realized foreign exchange losses on working capital items.

The change in non-cash working capital in 2017 was primarily due to a decrease in accounts receivable and inventory, partially offset by higher income tax receivable and a decrease in accounts payable. For 2016, the change in non-cash working capital was primarily due to an increase in accounts receivable and a rise in inventory, partially offset by an increase in accounts payable.

Operating Earnings (Loss)

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

($ millions)	**2017**	2016	2015
Earnings (Loss) From Continuing Operations, Before Income Tax	**2,216**	(802)	890
Add (Deduct):			
Unrealized Risk Management (Gain) Loss [(1)]	**729**	554	195
Non-Operating Unrealized Foreign Exchange (Gain) Loss [(2)]	**(651)**	(196)	1,064
Revaluation (Gain)	**(2,555)**	-	-
(Gain) Loss on Divestiture of Assets	**1**	6	(2,392)
Operating Earnings (Loss) From Continuing Operations, Before Income Tax	**(260)**	(438)	(243)
Income Tax Expense (Recovery)	**(226)**	(147)	(136)
Operating Earnings (Loss) From Continuing Operations	**(34)**	(291)	(107)
Operating Earnings (Loss) From Discontinued Operations	**160**	(86)	(296)
Total Operating Earnings (Loss)	**126**	(377)	(403)

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

Operating Earnings from continuing operations increased in 2017 compared with 2016 primarily due to higher cash from operating activities and Adjusted Funds Flow, as discussed above, greater unrealized foreign exchange gains on operating items compared with losses in 2016, and the re-measurement of the contingent payment, partially offset by an increase in depreciation, depletion and amortization ("DD&A") and exploration expense due to asset writedowns.

Net Earnings (Loss)

($ millions)	**2017 vs. 2016**	2016 vs. 2015
Net Earnings (Loss) From Continuing Operations, Comparative Year	**(459)**	914
Increase (Decrease) due to:		
Operating Margin From Continuing Operations	**1,769**	(276)
Corporate and Eliminations:		
Unrealized Risk Management Gain (Loss)	**(175)**	(359)
Unrealized Foreign Exchange Gain (Loss)	**668**	1,286
Revaluation Gain	**2,555**	-
Re-measurement of Contingent Payment	**138**	-
Gain (Loss) on Divestiture of Assets	**5**	(2,398)
Expenses [(1)]	**(149)**	(72)
DD&A	**(907)**	62
Exploration Expense	**(886)**	65
Income Tax Recovery (Expense)	**(291)**	319
Net Earnings (Loss) From Continuing Operations	**2,268**	(459)

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

Net Earnings from continuing operations in 2017 increased due to:

- The revaluation gain of $2,555 million related to the deemed disposition of our pre-existing interest in FCCL;
- Non-operating unrealized foreign exchange gains of $651 million compared with $196 million in 2016; and
- Higher Operating Earnings, as discussed above.

These increases were partially offset by a deferred income tax expense in 2017. The gain on the revaluation of our pre-existing interest in FCCL resulted in a deferred tax expense, which was partially offset by a recovery due to the reduction of the U.S. federal corporate income tax rate. In 2016, a deferred tax recovery was recorded largely due to risk management losses and the recognition of operating losses.

Net Earnings from discontinued operations in 2017 was $1,098 million, including an after-tax gain of $938 million on the divestiture of the Conventional segment assets. In 2016, discontinued operations generated a net loss of $86 million.

Net Capital Investment

($ millions)	2017	2016	2015
Oil Sands	**973**	604	1,185
Deep Basin	**225**	-	-
Refining and Marketing	**180**	220	248
Corporate and Eliminations	**77**	31	37
Capital Investment – Continuing Operations	**1,455**	855	1,470
Conventional (Discontinued Operations)	**206**	171	244
Total Capital Investment	**1,661**	1,026	1,714
Acquisitions (1)	**18,388**	11	87
Divestitures (1)	**(3,210)**	(8)	(3,344)
Net Capital Investment (2)	**16,839**	1,029	(1,543)

(1) In connection with the Acquisition that was completed in the second quarter of 2017, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and reacquired it at fair value as required by IFRS 3 "Business Combinations" ("IFRS 3"), which is not reflected in the table above. The carrying value of the pre-existing interest was $9,081 million and the estimated fair value was $11,605 million as at May 17, 2017.

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

Capital investment in continuing operations in 2017 increased $600 million compared with 2016, reflecting our increased ownership in FCCL through the Acquisition. Oil Sands capital investment focused on sustaining capital related to existing production; Christina Lake expansion phase G; and stratigraphic test wells to determine pad placement for sustaining wells, near-term expansion phases, and progression of certain emerging assets. Deep Basin capital investment related to asset development planning and our horizontal drilling and completion program targeting liquids-rich natural gas within the Deep Basin corridor.

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

Capital Investment Decisions

We have now completed the divestiture of our legacy Conventional assets. However, we continue to focus on deleveraging our balance sheet and are currently marketing for sale certain non-core Deep Basin Assets in order to further streamline our portfolio. In addition to our commitment to continue reducing our debt, we are actively identifying further cost reduction opportunities.

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

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

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

($ millions)	2017	2016	2015
Adjusted Funds Flow (1)	**2,914**	1,423	1,691
Total Capital Investment (1)	**1,661**	1,026	1,714
Free Funds Flow (1) (2)	**1,253**	397	(23)
Cash Dividends	**225**	166	528
	1,028	231	(551)

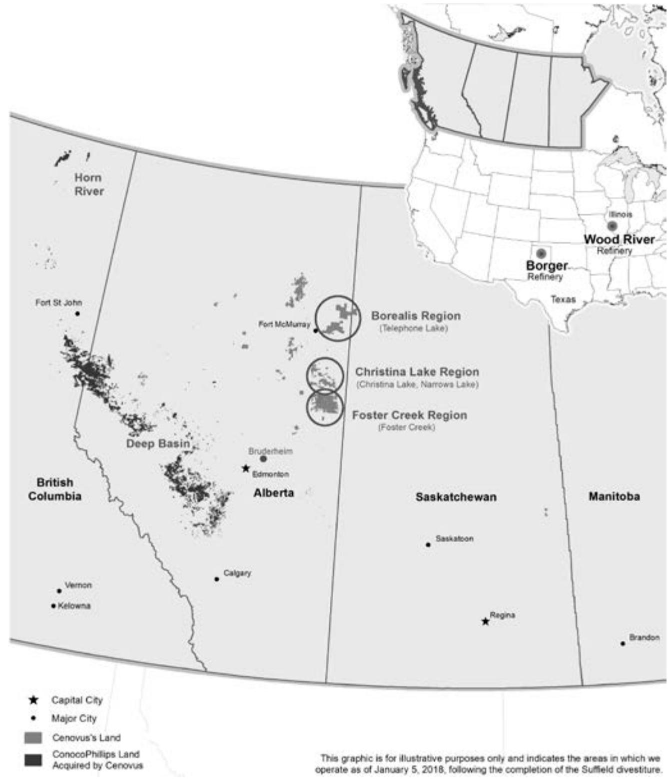
(1) Includes our Conventional segment, which has been classified as a discontinued operation.

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

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

REPORTABLE SEGMENTS

Our reportable segments are as follows:



Oil Sands, which includes the development and production of bitumen and natural gas in northeast Alberta. Cenovus's bitumen assets include Foster Creek, Christina Lake and Narrows Lake as well as other projects in the early stages of development. Our interest in certain of our operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake increased from 50 percent to 100 percent on May 17, 2017.

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

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

Corporate and Eliminations, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations relate to sales and operating revenues, and purchased product between segments, recorded at transfer prices based on current market prices, and to unrealized intersegment profits in inventory.

In 2017, Cenovus divested the majority of the crude oil and natural gas assets in the Company's Conventional segment. As such, the results of operations have been presented as a discontinued operation and all prior periods restated. This segment included the production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the CO_2 enhanced oil recovery project at Weyburn and emerging tight oil opportunities. As at December 31, 2017, all Conventional assets were sold, except for the Company's Suffield operations. The sale of the Suffield assets closed on January 5, 2018. Refer to the Discontinued Operations section of this MD&A for more information.

Revenues by Reportable Segment

($ millions)	**2017**	2016	2015
Oil Sands [1]	**7,132**	2,920	3,001
Deep Basin [2]	**514**	-	-
Refining and Marketing	**9,852**	8,439	8,805
Corporate and Eliminations	**(455)**	(353)	(277)
	17,043	11,006	11,529

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

OIL SANDS

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

Significant developments in our Oil Sands segment in 2017 compared with 2016 include:

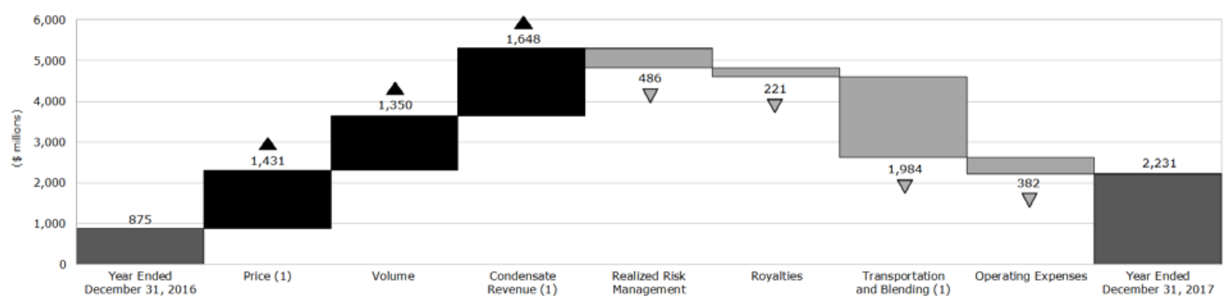
- Increasing our crude oil production by 95 percent primarily due to the Acquisition and incremental production volumes from Christina Lake phase F and Foster Creek phase G, both of which started up in the second half of 2016;
- Crude oil netbacks, excluding realized risk management activities, of $24.54 per barrel (2016 – $11.94 per barrel); and
- Generating Operating Margin net of capital investment of $1,214 million, an increase of $941 million.

Oil Sands – Crude Oil

Financial Results

($ millions)	**2017**	2016	2015
Gross Sales	**7,340**	2,911	3,000
Less: Royalties	**230**	9	29
Revenues	**7,110**	2,902	2,971
Expenses			
Transportation and Blending	**3,704**	1,720	1,814
Operating	**868**	486	511
(Gain) Loss on Risk Management	**307**	(179)	(400)
Operating Margin	**2,231**	875	1,046
Capital Investment	**969**	601	1,184
Operating Margin Net of Related Capital Investment	**1,262**	274	(138)

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 2017, our average crude oil sales price increased to $41.49 per barrel (2016 – $27.64 per barrel). The rise in our crude oil price was consistent with the increase in the WCS and Christina Dilbit Blend ("CDB") benchmark prices and the narrowing of the WCS-Condensate differential, partially offset by the strengthening of the Canadian dollar relative to the U.S. dollar. The WCS-CDB differential narrowed to a discount of US$1.67 per barrel (2016 - discount of US$2.05 per barrel).

Our crude oil sales price is influenced by the cost of condensate used in blending. Our blending ratios range between 25 percent and 33 percent. As the cost of condensate increases relative to the price of blended crude oil, our bitumen sales price decreases. Due to high demand for condensate at Edmonton, we also purchase condensate from U.S. markets. As such, our average cost of condensate is generally higher than the Edmonton benchmark price due to transportation between market hubs and transportation to field locations. In addition, up to three months may elapse from when we purchase condensate to when we blend it with our production. In a rising price environment, we expect to see some benefit in our bitumen sales price as we are using condensate purchased at a lower price earlier in the year.

Production Volumes

(barrels per day)	**2017**	**Percent Change**	2016	Percent Change	2015
Foster Creek	**124,752**	**78%**	70,244	7%	65,345
Christina Lake	**167,727**	**111%**	79,449	6%	74,975
	292,479	**95%**	149,693	7%	140,320

In 2017, production increased primarily due to incremental volumes at Foster Creek and Christina Lake of 48,080 barrels per day and 64,437 barrels per day, respectively, as a result of the Acquisition. The phase G expansion at Foster Creek and the phase F expansion at Christina Lake also contributed to higher volumes. Production at Foster Creek was reduced as a result of temporary treating issues and a 20-day planned turnaround completed in 2017.

Condensate

The bitumen currently produced by Cenovus must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential during 2017, the proportion of the cost of condensate recovered increased. The total amount of condensate used increased as a result of higher production volumes.

Royalties

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

Royalties at Foster Creek, a post-payout project, are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net profits of the project multiplied by the applicable royalty rate (25 to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales volumes and sales prices. Net profits are a function of sales volumes, sales prices and allowed operating and capital costs.

Royalties at Christina Lake, a pre-payout project, are based on a monthly calculation that applies a royalty rate (ranging from one to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project.

Effective Royalty Rates

(percent)	**2017**	2016	2015
Foster Creek	**11.4**	-	1.9
Christina Lake	**2.5**	1.6	2.8

Royalties increased $221 million in 2017 compared with 2016. Royalties at Foster Creek increased primarily due to a higher WTI benchmark price (which determines the royalty rate). The royalty calculation was based on net profits as compared with a calculation based on gross revenues for 2016, resulting in a significant increase in the royalty rate. In 2016, the low royalty rate was primarily due to low crude oil sales prices, a decline in the WTI benchmark price and a true-up of the 2015 royalty calculation.

Christina Lake royalties increased in 2017 primarily as a result of a rise in the WTI benchmark price (which determines the royalty rate) and higher crude oil sales prices.

Expenses

Transportation and Blending

Transportation and blending costs increased $1,984 million. Blending costs increased due to a rise in condensate volumes required for our increased production as well as higher condensate prices. Our condensate costs were higher than the average Edmonton benchmark price, primarily due to the transportation expense associated with moving the condensate between market hubs and to our oil sands projects.

Transportation costs increased primarily due to incremental sales volumes as a result of the Acquisition and expansion phases. In addition, rail costs rose as a result of moving higher volumes by rail over longer distances to U.S. markets. We transported an average of 9,743 barrels per day of crude oil by rail (2016 – 4,906 barrels per day).

Per-unit Transportation Expenses

At both Foster Creek and Christina Lake, per-barrel transportation costs declined primarily due to lower pipeline tariffs from an increase in the proportion of Canadian sales in 2017. Foster Creek per-barrel transportation costs were partially offset by higher rail costs from additional volumes shipped to the U.S. by unit trains.

Operating

Primary drivers of our operating expenses in 2017 were workforce costs, fuel, repairs and maintenance, chemical costs and workovers. While unit operating costs decreased six percent, total operating expenses increased $382 million primarily due to the Acquisition, higher fuel costs due to increased fuel consumption, additional repairs and maintenance, as well as increased chemical and workforce costs associated with the phase F expansion at Christina Lake. In addition, repairs and maintenance costs, as well as fluid, waste handling and trucking costs increased in 2017 due to the 20-day turnaround at Foster Creek.

Per-unit Operating Expenses

($/bbl)	**2017**	**Percent Change**	2016	Percent Change	2015
Foster Creek					
Fuel	**2.44**	**(1)%**	2.46	(12)%	2.80
Non-fuel	**8.02**	**(1)%**	8.09	(17)%	9.80
Total	**10.46**	**(1)%**	10.55	(16)%	12.60
Christina Lake					
Fuel	**2.06**	**(1)%**	2.08	(5)%	2.20
Non-fuel	**4.78**	**(11)%**	5.40	(7)%	5.81
Total	**6.84**	**(9)%**	7.48	(7)%	8.01
Total	**8.40**	**(6)%**	8.91	(12)%	10.13

At Foster Creek, per-barrel fuel costs decreased slightly due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses declined in 2017 primarily due to higher production, partially offset by higher repairs and maintenance, an increase in workover costs due to increased pump changes, higher chemical costs, as well as increased fluid, waste handling and trucking costs due to the 20-day planned turnaround in the second quarter. This represents the largest scale turnaround executed to date and it was completed under budget.

At Christina Lake, fuel costs declined on a per-barrel basis due to lower natural gas prices, partially offset by increased consumption. Per-barrel non-fuel operating expenses decreased primarily due to higher production, partially offset by increased workforce and chemical costs associated with the phase F expansion, as well as higher repairs and maintenance activities.

Netbacks [1]

	Foster Creek			Christina Lake		
($/bbl)	**2017**	2016	2015	**2017**	2016	2015
Sales Price	**43.75**	30.32	33.65	**39.78**	25.30	28.45
Royalties	**4.00**	(0.01)	0.47	**0.87**	0.33	0.67
Transportation and Blending	**8.73**	8.84	8.84	**4.52**	4.68	4.72
Operating Expenses	**10.46**	10.55	12.60	**6.84**	7.48	8.01
Netback Excluding Realized Risk Management	**20.56**	10.94	11.74	**27.55**	12.81	15.05
Realized Risk Management Gain (Loss)	**(2.95)**	3.51	8.60	**(2.99)**	3.08	7.33
Netback Including Realized Risk Management	**17.61**	14.45	20.34	**24.56**	15.89	22.38

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

Risk Management

Risk management activities in 2017 resulted in realized losses of $307 million (2016 – realized gains of $179 million), consistent with average benchmark prices exceeding our contract prices.

Oil Sands – Natural Gas

Oil Sands includes our natural gas operations in northeastern Alberta. A portion of the natural gas produced from our Athabasca property is used as fuel at Foster Creek. Our natural gas production in 2017, net of internal usage, was 10 MMcf per day (2016 – 17 MMcf per day).

Operating Margin was $1 million in 2017 (2016 – $4 million), decreasing as a result of lower natural gas volumes, partially offset by higher natural gas sales prices.

Oil Sands – Capital Investment

($ millions)	2017	2016	2015
Foster Creek	**455**	263	403
Christina Lake	**426**	282	647
	881	545	1,050
Narrows Lake	**12**	7	47
Telephone Lake	**34**	16	24
Grand Rapids (1)	**1**	6	38
Other (2)	**45**	30	26
Capital Investment (3)	**973**	604	1,185

(1) Grand Rapids asset was included in the Pelican Lake divestiture package; the divestiture closed on September 29, 2017.
(2) Includes new resource plays and Athabasca natural gas.
(3) Includes expenditures on PP&E, E&E assets and assets held for sale.

Existing Projects

Capital investment in 2017 increased by $369 million from 2016, reflecting our 100 percent ownership of FCCL as of May 17, 2017. At Foster Creek, capital investment in 2017 was focused on sustaining capital related to existing production and stratigraphic test wells. In 2016, capital investment included sustaining capital related to existing production and stratigraphic test wells, as well as capital associated with the completion of phase G.

In 2017, Christina Lake capital investment focused on sustaining capital related to existing production, the phase G expansion and stratigraphic test wells. In 2016, capital was focused on sustaining capital related to existing production, the completion of expansion phase F and stratigraphic test wells.

Capital investment at Narrows Lake in 2017 and 2016 primarily related to drilling of stratigraphic test wells to further progress the project, as well as preservation of equipment at site.

Emerging Projects

In 2017, Telephone Lake capital investment concentrated on drilling stratigraphic test wells to further assess the project. In 2016, spending was reduced in response to the low commodity price environment and focused on front-end engineering work for the central processing facility.

Drilling Activity

	Gross Stratigraphic Test Wells			Gross Production Wells (1)		
	2017	2016	2015	**2017**	2016	2015
Foster Creek	**96**	95	124	**41**	18	28
Christina Lake	**108**	104	40	**25**	35	67
	204	199	164	**66**	53	95
Narrows Lake	**2**	1	-	**-**	-	-
Telephone Lake	**13**	-	-	**-**	-	-
Other (2)	**1**	5	-	**-**	1	1
	220	205	164	**66**	54	96

(1) SAGD well pairs are counted as a single producing well.
(2) Includes Grand Rapids which was included in the Pelican Lake divestiture package; the divestiture closed on September 29, 2017.

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

Future Capital Investment

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

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

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

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

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

DD&A

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.

In 2017, Oil Sands DD&A increased $575 million primarily due to higher sales volumes as a result of the Acquisition. The average depletion rate was approximately $11.50 per barrel compared with $11.30 per barrel in 2016. Our DD&A rate increased primarily due to an increase in the carrying value of our assets as a result of the re-measurement of our pre-existing interest in FCCL and the acquisition of the additional 50 percent interest of FCCL, which was partially offset by proved reserve additions.

Future development costs declined due to cost savings at both Foster Creek and Christina Lake related to a reduction in per well costs and increased well pair spacing. This decline was partially offset by an increase in costs related to the expansion of the development area and inclusion of phase G costs at Christina Lake.

Exploration Expense

For the year ended December 31, 2017, Management has determined that costs incurred to date on certain E&E assets, primarily in the Greater Borealis area, were not recoverable. As a result, $888 million of previously capitalized costs were recorded as exploration expense. In 2016, exploration expense was $2 million.

Management's decision was based on a comprehensive review of spending to date, decisions to limit spending on these assets in recent years and the current business plan spending on the assets going forward. At this point, Management is not committing further material funding beyond that required to retain ownership of this significant resource. In addition, regulatory changes to the Oil Sands Royalty application process impact the economic viability of these projects. These assets reside primarily in the Borealis cash-generating unit ("CGU") within the Oil Sands segment.

DEEP BASIN

On May 17, 2017, we acquired the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets including undeveloped land, exploration and production assets, and related infrastructure in Alberta and British Columbia. Our Deep Basin Assets include approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, with an average working interest of 70 percent. In addition, the Deep Basin Assets include interests in numerous natural gas processing plants with an estimated net processing capacity of 1.4 Bcf per day. The Deep Basin Assets are expected to provide short-cycle development opportunities with high return potential that complement our long-term oil sands development. We have now successfully integrated the Deep Basin Assets, maintained business continuity and continue to deliver safe and reliable operations.

Significant developments in our Deep Basin segment in 2017 include:

- Successful integration of the Deep Basin Assets;
- Total capital investment of $225 million related to the drilling of 28 horizontal production wells targeting liquids rich natural gas, the completion of 20 wells, and bringing 14 wells on production;
- Netback of $7.32 per BOE;
- Total production from the date of the Acquisition averaging 117,138 BOE per day, equivalent to 73,492 BOE per day for the year; and
- Generating Operating Margin of $207 million.

Financial Results

($ millions)	May 17 – December 31, 2017
Gross Sales	**555**
Less: Royalties	**41**
Revenues	**514**
Expenses	
Transportation and Blending	**56**
Operating	**250**
Production and Mineral Taxes	**1**
Operating Margin	**207**
Capital Investment	**225**
Operating Margin Net of Related Capital Investment	**(18)**

Revenues

Price

	May 17 – December 31, 2017
NGLs ($/bbl)	**33.05**
Light and Medium Oil ($/bbl)	**60.01**
Natural Gas ($/mcf)	**2.03**
Total Oil Equivalent ($/BOE)	**19.52**

Our Deep Basin Assets produce a variety of products from natural gas, condensate, other NGLs (including ethane, propane, butane and pentane) and light and medium oil.

In 2017, revenues included $31 million of processing fee revenue related to our interests in natural gas processing facilities. We do not include processing fee revenue in our per-unit pricing metrics or our netbacks.

Production Volumes

	2017
Liquids	
NGLs (barrels per day)	**16,928**
Light and Medium Oil (barrels per day)	**3,922**
	20,850
Natural Gas (MMcf per day)	**316**
Total Production (BOE/day)	**73,492**
Natural Gas Production (percentage of total)	**72%**
Liquids Production (percentage of total)	**28%**

Royalties

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

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

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

In 2017, our effective royalty rate was 12.1 percent for liquids and 4.4 percent for natural gas.

Expenses

Transportation

Transportation costs capture charges for the movement of crude oil, natural gas and NGLs from the point of production to where the product is sold. In 2017, the majority of Deep Basin products were sold into the Alberta market. Transportation costs averaged $2.08 per BOE in 2017.

Operating

Primary drivers of our operating expenses in 2017 were related to workforce, repairs and maintenance, processing fee expenses, and property tax and lease costs. Since the Acquisition, optimization of maintenance processes has enabled the extension of maintenance intervals, resulting in increased runtimes and lower repairs and maintenance costs. In 2017, Deep Basin operating costs were $8.56 per BOE, in line with our expectations.

Netbacks

($/BOE)	May 17 – December 31, 2017
Sales Price	**19.52**
Royalties	**1.54**
Transportation and Blending	**2.08**
Operating Expenses	**8.56**
Production and Mineral Taxes	**0.02**
Netback Excluding Realized Risk Management	**7.32**
Realized Risk Management Gain (Loss)	**-**
Netback Including Realized Risk Management	**7.32**

Deep Basin – Capital Investment

In 2017, capital investment was focused on developing all three operating areas, and included the drilling of 24 net horizontal wells in addition to participating in the drilling of four non-operated net horizontal wells targeting liquids rich natural gas. The Elmworth-Wapiti operating area focused on drilling nine net horizontal production wells within the Falher and Montney plays, with five net completions. The Kaybob-Edson operating area focused on drilling seven net horizontal production wells within the Spirit River play and five net completions. The Clearwater operating area focused on drilling 12 net horizontal production wells within the Spirit River play and 10 net completions.

($ millions)	May 17 – December 31, 2017
Drilling and Completions	**152**
Facilities	**32**
Other	**41**
Capital Investment (1)	**225**

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

Drilling Activity

(net wells, unless otherwise stated)	May 17 – December 31, 2017
Drilled(1)	**28**
Completed	**20**
Tied-in	**14**

(1) *Includes 24 net horizontal wells and four non-operated net horizontal wells.*

Future Capital Investment

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

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

DD&A

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

As at December 31, 2017, it was determined that the carrying amount of the Clearwater CGU exceeded its recoverable amount, resulting in an impairment loss of $56 million. The impairment was recorded as additional DD&A. Future cash flows for the CGU declined due to lower forward crude oil prices and revisions to the development plan. Total Deep Basin DD&A was $331 million in 2017.

Assets and Liabilities Held for Sale

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

REFINING AND MARKETING

Cenovus is a 50 percent partner in the Wood River and Borger refineries, which are located in the U.S. and operated by our partner, Phillips 66. Our Refining and Marketing segment positions us to capture the value from crude oil production through to refined products such as diesel, gasoline and jet fuel. Our integrated approach provides a natural economic hedge against widening crude oil price differentials by providing lower feedstock prices to the Refineries. This segment captures our marketing and transportation initiatives as well as our crude-by-rail terminal operations located in Bruderheim, Alberta. In 2017, we loaded an average of 12,176 gross barrels per day (2016 – 11,584 gross barrels per day).

Significant developments that impacted our Refining and Marketing segment in 2017 compared with 2016 include:

- Generating Operating Margin of $598 million, a 73 percent increase from 2016; and
- Maintaining strong crude utilization and operating performance at the Refineries.

Refinery Operations [1]

	2017	2016	2015
Crude Oil Capacity (Mbbls/d)	**460**	460	460
Crude Oil Runs (Mbbls/d)	**442**	444	419
Heavy Crude Oil	**202**	233	200
Light/Medium	**240**	211	219
Refined Products (Mbbls/d)	**470**	471	444
Gasoline	**238**	236	228
Distillate	**149**	146	137
Other	**83**	89	79
Crude Utilization (percent)	**96**	97	91

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

On a 100 percent basis, the Refineries have a total processing capacity of approximately 460,000 gross barrels per day of crude oil, including processing capability of up to 255,000 gross barrels per day of blended heavy crude oil and 45,000 gross barrels per day of NGLs. The ability to process a wide slate of crude oils allows the Refineries to economically integrate heavy crude oil production. Processing less expensive crude oil relative to WTI creates a feedstock cost advantage, illustrated by the discount of WCS relative to WTI. The amount of heavy crude oil processed, such as WCS and CDB, is dependent on the quality and quantity of available crude oil with the total input slate optimized at each refinery to maximize economic benefit. Crude utilization represents the percentage of total crude oil processed in the Refineries relative to the total capacity.

Crude oil runs and refined product output in 2017 were consistent with 2016. The planned turnarounds and maintenance and unplanned maintenance at both refineries in 2017 had a similar impact on crude oil runs and refined product output as the planned and unplanned maintenance in 2016. Lower heavy crude oil volumes were processed due to optimization of the total crude input slate.

Financial Results

($ millions)	**2017**	2016	2015
Revenues	**9,852**	8,439	8,805
Purchased Product	**8,476**	7,325	7,709
Gross Margin	**1,376**	1,114	1,096
Expenses			
Operating	**772**	742	754
(Gain) Loss on Risk Management	**6**	26	(43)
Operating Margin	**598**	346	385
Capital Investment	**180**	220	248
Operating Margin Net of Related Capital Investment	**418**	126	137

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 2017, Refining and Marketing gross margin increased primarily due to:

- Higher average market crack spreads; and
- Increased margins on the sale of our secondary products, such as NGLs, due to higher realized prices.

These increases in gross margin were partially offset by:

- Narrowing heavy crude oil differentials, increasing the cost of purchased crude; and
- The strengthening of the Canadian dollar relative to the U.S. dollar, which had a negative impact of approximately $27 million on our gross margin.

The costs associated with Renewable Identification Numbers ("RINs") were $296 million in 2017 (2016 – $294 million). The costs of RINs remained relatively consistent as the decrease in RINs benchmark prices was offset by an increase in the required RINs volume obligation.

Operating Expense

Primary drivers of operating expenses were labour, maintenance, utilities and supplies. In 2017, operating expenses increased due to an increase in maintenance costs associated with the plant turnarounds in the first quarter of 2017, and higher utility costs resulting from higher natural gas prices.

Refining and Marketing – Capital Investment

($ millions)	**2017**	2016	2015
Wood River Refinery	**114**	147	162
Borger Refinery	**54**	66	78
Marketing	**12**	7	8
	180	220	248

Capital expenditures in 2017 focused on capital maintenance and reliability work. Capital investment declined primarily due to the completion of work on the debottlenecking project at the Wood River refinery in the third quarter of 2016.

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

DD&A

Refining and the crude-by-rail terminal assets are depreciated on a straight-line basis over the estimated service life of each component of the facilities, which range from three to 40 years. The service lives of these assets are reviewed on an annual basis. Refining and Marketing DD&A was $215 million in 2017 compared with $211 million in 2016.

CORPORATE AND ELIMINATIONS

The Corporate and Eliminations segment includes intersegment eliminations relating to transactions that have been recorded at transfer prices based on current market prices, as well as unrealized intersegment profits in inventory. The gains and losses on risk management represent the unrealized mark-to-market gains and losses related to derivative financial instruments used to mitigate fluctuations in commodity prices, power costs, interest rates, and foreign exchange rates, as well as realized risk management gains, if any, on interest rate swaps and foreign exchange contracts. In 2017, our risk management activities resulted in $729 million of unrealized losses (2016 – $554 million of unrealized losses). As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. In 2017, we realized $146 million of risk management gains on foreign exchange contracts primarily due to hedging activity undertaken to support the Acquisition which were reported in the Corporate and Eliminations segment.

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

($ millions)	**2017**	2016	2015
General and Administrative	**308**	326	335
Finance Costs	**645**	390	381
Interest Income	**(62)**	(52)	(28)
Foreign Exchange (Gain) Loss, Net	**(812)**	(198)	1,036
Revaluation (Gain)	**(2,555)**	-	-
Transaction Costs	**56**	-	-
Re-measurement of Contingent Payment	**(138)**	-	-
Research Costs	**36**	36	27
(Gain) Loss on Divestiture of Assets	**1**	6	(2,392)
Other (Income) Loss, Net	**(5)**	34	2
	(2,526)	542	(639)

Expenses

General and Administrative

Primary drivers of our general and administrative expenses in 2017 were workforce costs and office rent. In 2017, general and administrative expenses decreased by $18 million compared with 2016 due to:

- Lower long-term employee incentive costs related to a decline in our share price;
- A non-cash expense of $9 million for certain Calgary office space in excess of Cenovus's current and near-term requirements, compared with $61 million in 2016; and
- Lower information technology costs due to process improvements.

Office rent, which makes up a large percentage of our G&A at $95 million, was consistent with 2016.

These decreases were partially offset by approximately $40 million of transitional services provided by ConocoPhillips. Under the Acquisition purchase and sales agreement, ConocoPhillips agreed to provide certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions are in the normal course of operations and are measured at the exchange amounts.

Finance Costs

Finance costs include interest expense on our long-term debt and short-term borrowings as well as the unwinding of the discount on decommissioning liabilities. In 2017, finance costs increased by $255 million primarily due to costs associated with additional debt incurred to finance the Acquisition, including US$2.9 billion of senior unsecured notes and $3.6 billion borrowed under a committed Bridge Facility. The committed Bridge Facility was fully repaid and retired in December 2017 with proceeds from the sale of our legacy Conventional assets and cash on hand.

The weighted average interest rate on outstanding debt for 2017 was 4.9 percent (2016 – 5.3 percent).

Foreign Exchange

($ millions)	**2017**	2016	2015
Unrealized Foreign Exchange (Gain) Loss	**(857)**	(189)	1,097
Realized Foreign Exchange (Gain) Loss	**45**	(9)	(61)
	(812)	(198)	1,036

In 2017, unrealized foreign exchange gains of $665 million resulted from the translation of our U.S. dollar denominated debt. The Canadian dollar relative to the U.S. dollar as at December 31, 2017 strengthened by seven percent in comparison to December 31, 2016. Unrealized foreign exchange gains also resulted from the translation of U.S. cash that was accumulated in advance of the Acquisition.

Realized foreign exchange losses in 2017 primarily resulted from an increase in the number of sales contracts denominated in U.S. dollars.

Revaluation Gain

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

Transaction Costs

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

Re-measurement of Contingent Payment

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

The contingent payment is accounted for as a financial option. The fair value of $361 million on May 17, 2017 was estimated by calculating the present value of the future expected cash flows using an option pricing model. The contingent payment is subsequently re-measured at fair value at each reporting date with changes in fair value recognized in net earnings. At December 31, 2017, the contingent payment was valued at $206 million, resulting in a re-measurement gain of $138 million. In the fourth quarter of 2017, WCS averaged above $52 per barrel; therefore, $17 million is payable under this agreement.

Average WCS forward pricing for the remaining term of the contingent payment is US$35.51 or C$44.55 per barrel. Estimated quarterly WCS forward prices for the remaining term of the agreement range between approximately C$39.60 per barrel and C$52.60 per barrel.

DD&A

Corporate and Eliminations DD&A includes provisions in respect of corporate assets, such as computer equipment, leasehold improvements and office furniture. Costs associated with corporate assets are depreciated on a straight-line basis over the estimated service life of the assets, which range from three to 25 years. The service lives of these assets are reviewed on an annual basis. DD&A in 2017 was $62 million (2016 – $65 million; 2015 – $105 million).

Income Tax

($ millions)	2017	2016	2015
Current Tax			
Canada	**(217)**	(260)	441
United States	**(38)**	1	(12)
Current Tax Expense (Recovery)	**(255)**	(259)	429
Deferred Tax Expense (Recovery)	**203**	(84)	(453)
Total Tax Expense (Recovery) From Continuing Operations	**(52)**	(343)	(24)

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

($ millions)	2017	2016	2015
Earnings (Loss) From Continuing Operations Before Income Tax	**2,216**	(802)	890
Canadian Statutory Rate	**27.0%**	27.0%	26.1%
Expected Income Tax Expense (Recovery) From Continuing Operations	**598**	(217)	232
Effect of Taxes Resulting From:			
Foreign Tax Rate Differential	**(17)**	(46)	(41)
Non-Taxable Capital (Gains) Losses	**(148)**	(26)	137
Non-Recognition of Capital (Gains) Losses	**(118)**	(26)	135
Adjustments Arising From Prior Year Tax Filings	**(41)**	(46)	(55)
(Recognition) of Previously Unrecognized Capital Losses	**(68)**	-	(149)
(Recognition) of U.S. Tax Basis	**-**	-	(415)
Change in Statutory Rate	**(275)**	-	114
Non-Deductible Expenses	**(5)**	5	7
Other	**22**	13	11
Total Tax Expense (Recovery) From Continuing Operations	**(52)**	(343)	(24)
Effective Tax Rate	**(2.3)%**	(42.8)%	(2.7)%

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

In 2017, a current tax recovery was recorded in continuing operations resulting from the carry back of current and prior year losses and an adjustment related to prior years. A deferred tax expense was recorded in 2017 compared with a recovery in 2016 on continuing operations due to the revaluation gain of our pre-existing interest in connection with the Acquisition, partially offset by a $275 million recovery from the reduction of the U.S. federal corporate income tax rate from 35 to 21 percent, reducing our deferred income tax liability, and the impact of E&E writedowns.

In 2017, the U.S. issued new tax legislation which:

- Reduces the federal income tax rate from 35 percent to 21 percent;
- Permits the full deductibility of allowed capital expenditures until January 1, 2023;
- Limits the use of operating tax losses incurred after 2017 to 80 percent of taxable income;
- Limits the deductibility of interest expense to 30 percent of “adjusted taxable income”; and
- Introduces a base erosion and anti-abuse tax that imposes a five percent minimum tax in 2018, increasing to 10 percent in 2019, to the extent that a corporation makes significant tax deductible payments to a related party.

In 2017, we recorded an income tax expense of $404 million related to discontinued operations (2016 – income tax recovery of $39 million), of which $347 million deferred tax expense relates to the gain on discontinuance.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate as it reflects different tax rates in other jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other tax legislation, adjustments to the tax basis of the refining assets, variations in the estimate of reserves, differences between the provision and the actual amounts subsequently reported on the tax returns, and other permanent differences. Our effective tax rate differs from the statutory tax rate due to non-taxable foreign exchange gains and the recognition of the benefit of other capital losses and a recovery relating to the change in the U.S. federal tax rate.

DISCONTINUED OPERATIONS

Following the Acquisition, we announced our intention to divest all of our legacy Conventional assets and therefore the Conventional segment has been reported as a discontinued operation.

In late 2017, we sold the majority of our legacy Conventional assets. The sale of Suffield, the one remaining legacy asset as at December 31, 2017, closed on January 5, 2018 for gross proceeds of $512 million. The divestitures completed in 2017 generated total gross cash proceeds of $3.2 billion before closing adjustments and a before-tax gain of $1.3 billion. Details of the asset sales are:

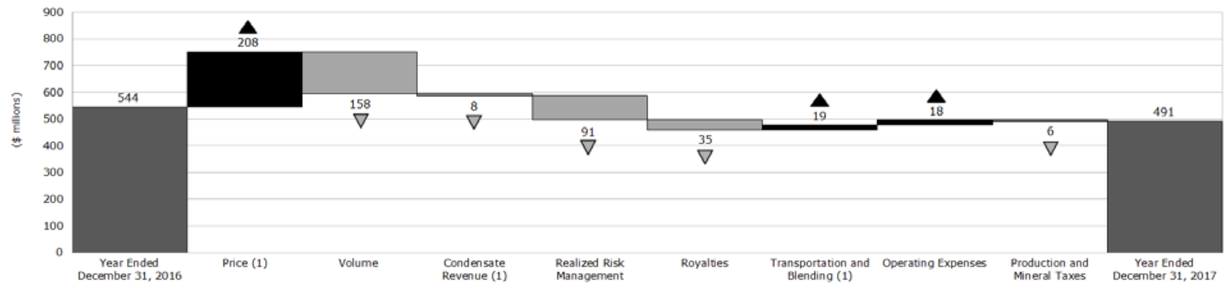
- On September 29, 2017, we completed the sale of our Pelican Lake heavy oil operations, as well as other miscellaneous assets in northern Alberta, for gross cash proceeds of $975 million before closing adjustments. A before-tax loss on discontinuance of $623 million was recorded on the sale;
- On December 7, 2017, our Palliser crude oil and natural gas operations in southern Alberta were sold for gross cash proceeds of $1.3 billion before closing adjustments. A before-tax gain on discontinuance of $1.6 billion was recorded on the sale; and
- On December 14, 2017, the sale of our Weyburn assets in southern Saskatchewan was completed for gross cash proceeds of $940 million before closing adjustments. A before-tax gain on discontinuance of $276 million was recorded on the sale.

Financial Results

($ millions)	**2017**	2016	2015
Gross Sales	**1,309**	1,267	1,648
Less: Royalties	**174**	139	113
Revenues	**1,135**	1,128	1,535
Expenses			
Transportation and Blending	**167**	186	229
Operating	**426**	444	558
Production and Mineral Taxes	**18**	12	17
(Gain) Loss on Risk Management	**33**	(58)	(209)
Operating Margin	**491**	544	940
Depreciation, Depletion and Amortization	**192**	567	1,121
Exploration Expense	**2**	-	71
Finance Costs	**80**	102	101
Earnings (Loss) From Discontinued Operations Before Income Tax	**217**	(125)	(353)
Current Tax Expense (Recovery)	**24**	86	145
Deferred Tax Expense (Recovery)	**33**	(125)	(202)
After-tax Earnings (Loss) From Discontinued Operations	**160**	(86)	(296)
After-tax Gain on Discontinuance [(1)]	**938**	-	-
Net Earnings (Loss) From Discontinued Operations	**1,098**	(86)	(296)

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

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

	2017	2016	2015
Total Liquids ($/bbl)	**52.38**	40.67	44.31
Natural Gas ($/mcf)	**2.47**	2.33	2.92
Total Oil Equivalent ($/BOE)	**32.10**	26.54	30.51

Our Conventional assets produced a variety of natural gas, NGLs, condensate and crude oils, ranging from heavy oil, which realizes a price based on the WCS benchmark, to light oil, which realizes a price closer to the WTI benchmark.

Production Volumes

(barrels per day)	**2017**	**Percent Change**	2016	Percent Change	2015
Liquids					
Heavy Oil	**21,478**	**(26)%**	29,185	(15)%	34,256
Light and Medium Oil	**24,824**	**(4)%**	25,915	(10)%	28,675
NGLs	**1,073**	**1%**	1,065	(7)%	1,149
Total Liquids Production (barrels per day)	**47,375**	**(16)%**	56,165	(12)%	64,080
Natural Gas (MMcf per day)	**333**	**(12)%**	377	(8)%	412
Total Production (BOE per day)	**102,855**	**(14)%**	118,998	(10)%	132,746

Total production decreased primarily due to the divestiture of our Conventional assets late in 2017 and expected natural declines. These decreases were partially offset by an increase in production associated with our tight oil drilling program in southern Alberta.

Condensate

Heavy oil currently must be blended with condensate to reduce its thickness in order to transport it to market through pipelines. Blending ratios for Conventional heavy oil ranged between 10 percent and 16 percent. Revenues represent the total value of blended crude oil sold and include the value of condensate. Consistent with the narrowing of the WCS-Condensate differential in 2017, the proportion of the cost of condensate recovered increased.

Royalties

Royalties increased $35 million in 2017 primarily due to an increase in our liquids sales prices, higher royalty rates, and lower allowable costs for royalty purposes at Weyburn and Pelican Lake, partially offset by a reduction in sales volumes. In 2017, the effective liquids royalty rate was 19.3 percent (2016 – 16.3 percent) and the average natural gas royalty rate was 4.8 percent (2016 – 4.7 percent).

Expenses

Transportation and Blending

Transportation and blending costs decreased $19 million in 2017 primarily due to the sale of Pelican Lake completed on September 29, 2017, resulting in lower production as well as a decrease in blended condensate volumes. This decrease was partially offset by higher blending costs as a result of increased condensate prices.

Operating

Primary drivers of our operating expenses in 2017 were property taxes and lease costs, workforce costs, workover activities, electricity, and repairs and maintenance. Operating expenses increased $1.02 per barrel. The per unit increase was primarily due to lower production volumes, an increase in repairs and maintenance activities, and higher energy costs. This increase was partially offset by reduced workforce costs, lower property and lease costs, fewer workovers and a decrease in electricity costs due to lower consumption and price.

In 2017, production and mineral taxes increased due to the rise in crude oil prices.

Netbacks

($/BOE)	**2017**	2016	2015
Sales Price	**32.10**	26.54	30.51
Royalties	**4.65**	3.18	2.33
Transportation and Blending	**1.93**	2.08	1.88
Operating Expenses	**11.25**	10.23	11.58
Production and Mineral Taxes	**0.49**	0.27	0.35
Netback Excluding Realized Risk Management	**13.78**	10.78	14.37
Realized Risk Management Gain (Loss)	**(0.88)**	1.45	4.50
Netback Including Realized Risk Management	**12.90**	12.23	18.87

Risk Management

Risk management activities for 2017 resulted in realized losses of $33 million (2016 – realized gains of $58 million), consistent with average benchmark prices exceeding our contract prices.

Net Earnings (Loss) From Discontinued Operations

Net Earnings From Discontinued Operations was $1,098 million in 2017 compared with a loss of $86 million in 2016. The significant increase was due to the after-tax gain on discontinuance of $938 million, and lower DD&A expense due to the decision to divest our Conventional assets, partially offset by higher tax expense and a decline in operating margin.

Conventional – Capital Investment

($ millions)	**2017**	2016	2015
Heavy Oil	**32**	44	63
Light and Medium Oil	**163**	117	168
Natural Gas	**11**	10	13
Capital Investment (1)	**206**	171	244

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

Capital investment in 2017 was primarily related to sustaining capital, the purchase of CO_2 at Weyburn, and tight oil drilling opportunities in southern Alberta. Our drilling program was suspended early in the third quarter of 2017 in anticipation of the asset divestitures. Capital investment increased compared with 2016 as a result of limited crude oil capital investment activities in 2016 in response to the low commodity price environment.

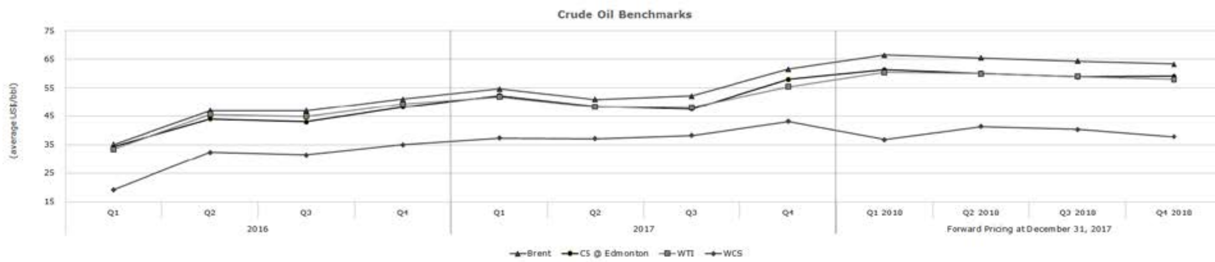
DD&A

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

DD&A decreased $375 million year over year primarily due to impairment losses of $445 million recorded in 2016, and a decline in sales volumes. In addition, on classification of our Conventional assets as held for sale in the first and second quarters of 2017, DD&A was no longer recorded, as required by IFRS.

QUARTERLY RESULTS

Our quarterly results over the last eight quarters were impacted primarily by volatility in commodity prices, with the Acquisition having a significant impact on the last three quarters. Crude oil prices reached a 13 year low, with WTI averaging US$33.45 per barrel in the first quarter of 2016 and gradually increasing to an average of US$55.40 per barrel in the fourth quarter of 2017. Average WTI and WCS benchmark prices increased 12 percent and 23 percent, respectively in the fourth quarter 2017 compared with 2016. Our companywide Netback from continuing operations of $22.38 per BOE in the fourth quarter of 2017, before realized risk management activities, increased six percent compared with 2016.



($ millions, except per share amounts or where otherwise indicated)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Production Volumes								
Total Liquids (barrels per day)	**422,157**	**449,055**	**333,664**	**234,914**	219,551	208,072	198,080	197,551
Natural Gas (MMcf/d)	**795**	**851**	**620**	**363**	379	392	399	408
Total Production (BOE per day)	**554,606**	**590,851**	**436,929**	**295,414**	282,718	273,405	264,580	265,551
Total Production From Continuing Operations (BOE per day)	**480,497**	**478,817**	**322,792**	**184,001**	167,230	156,591	145,604	140,808
Refinery Operations								
Crude Oil Runs (Mbbls/d)	**450**	**462**	**449**	**406**	421	463	458	435
Refined Products (Mbbls/d)	**480**	**490**	**476**	**433**	448	494	483	460
Revenues	**5,079**	**4,386**	**4,037**	**3,541**	3,324	2,945	2,746	1,991
Operating Margin (1)								
From Continuing Operations	**1,018**	**1,097**	**572**	**305**	442	335	424	22
Total Operating Margin	**1,088**	**1,214**	**731**	**450**	595	487	541	144
Cash From Operating Activities								
From Continuing Operations	**833**	**481**	**1,102**	**195**	22	189	121	94
Total Cash From Operating Activities	**900**	**592**	**1,239**	**328**	164	310	205	182
Adjusted Funds Flow (2)								
From Continuing Operations	**796**	**865**	**603**	**183**	382	296	352	(65)
Total Adjusted Funds Flow	**866**	**980**	**745**	**323**	535	422	440	26
Operating Earnings (Loss) (2)								
From Continuing Operations	**(533)**	**240**	**298**	**(39)**	21	(40)	(3)	(269)
Per Share – Diluted ($)	**(0.43)**	**0.20**	**0.27**	**(0.05)**	0.03	(0.05)	-	(0.32)
Total Operating Earnings (Loss)	**(514)**	**327**	**352**	**(39)**	321	(236)	(39)	(423)
Per Share – Diluted ($)	**(0.42)**	**0.27**	**0.32**	**(0.05)**	0.39	(0.28)	(0.05)	(0.51)
Net Earnings (Loss)								
From Continuing Operations	**(776)**	**275**	**2,558**	**211**	(209)	(55)	(231)	36
Per Share – Basic and Diluted ($)	**(0.63)**	**0.22**	**2.30**	**0.25**	(0.25)	(0.07)	(0.28)	0.04
Total Net Earnings (Loss)	**620**	**(82)**	**2,617**	**211**	91	(251)	(267)	(118)
Per Share – Basic and Diluted ($)	**0.50**	**(0.07)**	**2.35**	**0.25**	0.11	(0.30)	(0.32)	(0.14)
Capital Investment (3)								
From Continuing Operations	**557**	**396**	**277**	**225**	202	167	202	284
Total Capital Investment	**583**	**438**	**327**	**313**	259	208	236	323
Dividends								
Cash Dividends	**61**	**62**	**61**	**41**	42	41	42	41
Per Share ($)	**0.05**	**0.05**	**0.05**	**0.05**	0.05	0.05	0.05	0.05

(1) Additional subtotal found in Note 1 and Note 11 of the Consolidated Financial Statements and defined in this MD&A.
(2) Non-GAAP measure defined in this MD&A.
(3) Includes expenditures on PP&E, E&E assets, and assets held for sale.
(4) In the second quarter of 2017, the Company's Conventional segment was classified as a discontinued operation. Prior periods have been restated to reflect this classification.

Fourth Quarter 2017 Results Compared With the Fourth Quarter 2016

Continuing Operations

Production Volumes

Total production from continuing operations increased 187 percent in the fourth quarter of 2017 compared with 2016. The increase in production was primarily due to the Acquisition and the incremental production volumes from Christina Lake phase F, which started up in the fourth quarter of 2016.

Refinery Operations

Crude oil runs and refined product output increased in 2017 primarily due to unplanned outages at the Borger refinery in the fourth quarter of 2016.

Revenues

Revenues increased $1,755 million in 2017 primarily due to:

- A rise in sales volumes due to the Acquisition and the incremental production volumes from Christina Lake phase F;
- A 25 percent rise in our liquids sales prices from continuing operations to $45.85 per barrel; and
- An increase in refining revenues largely due to higher refined product pricing.

The increases to revenues were partially offset by lower revenues from third-party crude oil and natural gas sales undertaken by the marketing group, the strengthening of the Canadian dollar relative to the U.S. dollar, as well as higher crude oil royalties.

Operating Margin

Operating Margin from continuing operations increased 130 percent in the fourth quarter of 2017 compared with 2016. Upstream Operating Margin rose 111 percent primarily due to an increase in our liquids and natural gas sales volumes as a result of the Acquisition and a rise in our average liquids sales prices due to improved benchmark prices.

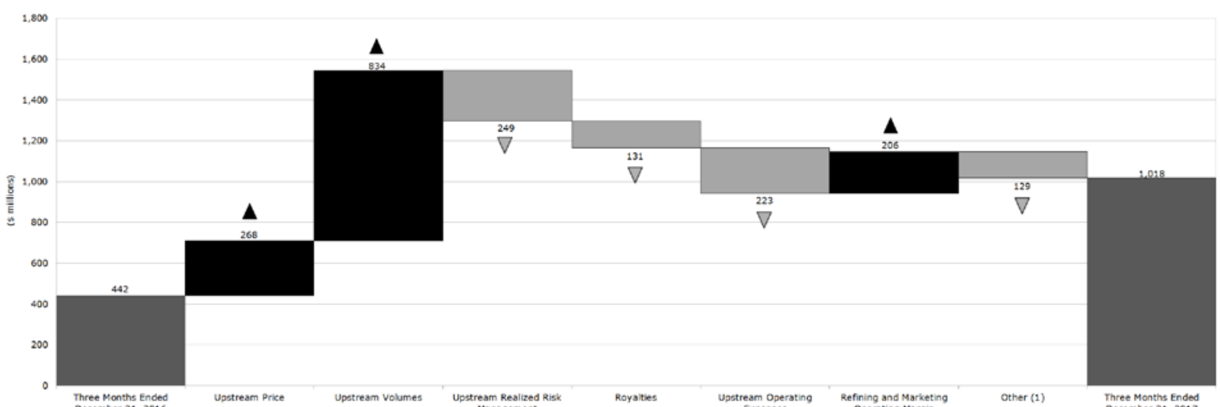
These increases were partially offset by:

- A rise in transportation and blending expenses related to higher condensate prices and a rise in condensate volumes required for our increased production;
- Realized risk management losses of $235 million compared with gains of $14 million in 2016;
- An increase in upstream operating expenses primarily due to the Acquisition;
- Higher royalties primarily due to an increase in the WTI benchmark price (which determines the royalty rate), increased sales volumes due to the Acquisition, and a rise in our liquids sales price; and
- Lower average natural gas sales prices, consistent with the decline in the AECO benchmark price.

Refining and Marketing Operating Margin increased by $206 million. The increase was primarily due to higher average market crack spreads, a rise in margins on the sale of our secondary products, and an increase in crude utilization rates.

These increases were partially offset by narrowing heavy crude oil differentials, increased operating costs and the strengthening of the Canadian dollar relative to the U.S. dollar.

Operating Margin From Continuing Operations Variance



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

Discontinued Operations

Production Volumes

Total production decreased 36 percent in the fourth quarter of 2017 compared with 2016, primarily as a result of the divestiture of our Conventional assets late in 2017 as well as expected natural declines.

Operating Margin

Operating Margin decreased 54 percent in the fourth quarter of 2017 compared with 2016, primarily as a result of reduced sales volumes due to the sale of the majority of our legacy Conventional assets and natural declines, partially offset by a decrease in royalties.

Consolidated Operations

Cash From Operating Activities and Adjusted Funds Flow

Total Cash From Operating Activities and Adjusted Funds Flow increased in the fourth quarter of 2017 compared with 2016, primarily due to a higher Operating Margin, as discussed above, partially offset by current income tax expense in 2017 compared with a recovery in 2016 and a rise in finance costs primarily associated with additional debt incurred to finance the Acquisition.

The change in non-cash working capital in the fourth quarter of 2017 was primarily due to an increase in accounts payable and income tax payable, partially offset by an increase in accounts receivable and inventory. For 2016, the change in non-cash working capital was primarily due to an increase in accounts receivable and a rise in inventory, partially offset by an increase in accounts payable.

Operating Earnings (Loss)

Operating Earnings from continuing operations decreased $554 million in the three months ended December 31, 2017 compared with 2016. Higher Cash From Operating Activities and Adjusted Funds Flow, as discussed above, was more than offset by exploration expense of $887 million, and an increase in DD&A as a result of the Acquisition.

Operating Earnings from discontinued operations of $19 million decreased $281 million in the three months ended December 31, 2017 compared with 2016 due to a decrease in production volumes and operating margin, as discussed above. In addition, 2016 included an impairment reversal of $462 million which arose primarily due to the increase in our Northern Alberta CGU's estimated recoverable amount caused by a reduction in expected average future operating costs and lower future development costs, partially offset by a decline in estimated reserves.

Net Earnings (Loss)

Net loss from continuing operations for the three months ended December 31, 2017 increased $567 million compared with 2016. The increase in net loss was primarily due to lower operating earnings, as discussed above, and unrealized risk management losses of $654 million compared with $114 million in 2016, partially offset by non-operating unrealized foreign exchange losses of $51 million compared with $152 million in 2016. In addition, a deferred tax recovery of $275 million was recorded to reflect the benefit of the decreased U.S. federal corporate income tax rate.

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

Capital Investment

Capital investment from continuing operations in the fourth quarter of 2017 was $557 million, an increase of $355 million from 2016. The increase was primarily due to the drilling and completion of horizontal production wells within the Deep Basin corridor.

Capital investment from discontinued operations was down 54 percent to $26 million in the fourth quarter of 2017 compared with 2016 due to reduced spending as a result of the decision to divest our legacy Conventional assets in first and second quarters of 2017.

OIL AND GAS RESERVES

We retain IQREs to evaluate and prepare reports on 100 percent of our bitumen, heavy oil, light and medium oil, NGLs, conventional natural gas and shale gas proved and probable reserves.

Developments in 2017 compared with 2016 include:

- Bitumen proved reserves increasing 103 percent primarily due to the acquisition of the remaining 50 percent working interest in FCCL. In addition, 169 million barrels of proved reserves were added at Foster Creek and Narrows Lake as a result of the Alberta Energy Regulator's (the "AER") approval of expansions converting probable reserves to proved reserves, and from improved reservoir performance;
- Proved plus probable bitumen reserves increasing 92 percent as the acquisition of the remaining 50 percent working interest in FCCL was partially offset by the Grand Rapids divestiture;
- Heavy oil proved reserves declining 87 percent and heavy oil proved plus probable reserves declining 86 percent primarily due to the divestiture of Pelican Lake;
- Both light and medium oil proved reserves and proved plus probable reserves decreasing 87 percent, primarily as a result of the Palliser and Weyburn dispositions;
- NGLs proved and probable reserves increasing 101 million barrels and 67 million barrels, respectively, due to the acquisition of the Deep Basin Assets;
- Conventional natural gas proved reserves increased by 1,175 billion cubic feet and conventional natural gas probable reserves increased by 648 billion cubic feet as the acquisition of the Deep Basin Assets more than offset the Palliser disposition; and
- Shale gas proved and proved plus probable reserves of 283 billion cubic feet and 568 billion cubic feet, respectively, were booked as a result of the acquisition of the Deep Basin Assets.

The reserves data that follows is presented as at December 31, 2017 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 inflation is dated January 1, 2018. Comparative information as at December 31, 2016 uses McDaniel's January 1, 2017 forecast prices and inflation.

Reserves

As at December 31, 2017 (before royalties) [(1)]	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (Bcf)	Shale Gas (Bcf)	Total (MMBOE)
Proved	4,750	15	13	103	1,827	283	5,232
Probable	1,633	12	6	68	860	285	1,910
Proved plus Probable	6,383	27	19	171	2,687	568	7,142

(1) Includes reserves associated with the Suffield asset sold January 5, 2018, representing before royalties 69 MMBOE and 82 MMBOE on a proved and proved plus probable basis, respectively.

Reconciliation of Proved Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [(1)] (Bcf)	Shale Gas (Bcf)	Total (MMBOE)
December 31, 2016	2,343	114	99	2	652	-	2,667
Extensions and Improved Recovery	141	-	-	1	35	-	148
Discoveries	-	2	-	-	-	-	2
Technical Revisions	28	2	-	-	86	-	43
Economic Factors	-	-	-	-	-	-	-
Acquisitions	2,345	-	14	108	1,557	289	2,775
Dispositions	-	(95)	(90)	(2)	(266)	-	(231)
Production [(2)]	(107)	(8)	(10)	(6)	(237)	(6)	(172)
December 31, 2017	4,750	15	13	103	1,827	283	5,232
Year Over Year Change	2,407	(99)	(86)	101	1,175	283	2,565
	103%	(87)%	(87)%	5,050%	180%	-%	96%

(1) Includes coal bed methane ("CBM") as at December 31, 2016. No CBM remains at December 31, 2017 due to dispositions.
(2) Production includes the natural gas used as a fuel source in our oil sands operations and excludes royalty interest production.

Reconciliation of Probable Reserves

(before royalties)	Bitumen (MMbbls)	Heavy Oil (MMbbls)	Light & Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas [(1)] (Bcf)	Shale Gas (Bcf)	Total (MMBOE)
December 31, 2016	**976**	**75**	**43**	**1**	**212**	**-**	**1,130**
Extensions and Improved Recovery	**(141)**	**-**	**-**	**3**	**21**	**15**	**(132)**
Discoveries	**-**	**7**	**-**	**-**	**-**	**-**	**7**
Technical Revisions	**(10)**	**-**	**-**	**-**	**(3)**	**-**	**(10)**
Economic Factors	**-**	**-**	**-**	**-**	**-**	**-**	**-**
Acquisitions	**887**	**-**	**6**	**65**	**748**	**270**	**1,128**
Dispositions	**(79)**	**(70)**	**(43)**	**(1)**	**(118)**	**-**	**(213)**
Production	**-**	**-**	**-**	**-**	**-**	**-**	**-**
December 31, 2017	**1,633**	**12**	**6**	**68**	**860**	**285**	**1,910**
Year Over Year Change	**657**	**(63)**	**(37)**	**67**	**648**	**285**	**780**
	67%	**(84)%**	**(86)%**	**6,700%**	**306%**	**-%**	**69%**

(1) *Includes CBM as at December 31, 2016. No CBM remains at December 31, 2017 due to dispositions.*

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, 2017. 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)	2017	2016	2015
Cash From (Used In)			
Operating Activities – Continuing Operations	**2,611**	426	696
Operating Activities – Discontinued Operations	**448**	435	778
Total Operating Activities	**3,059**	861	1,474
Investing Activities – Continuing Operations	**(15,859)**	(911)	1,131
Investing Activities – Discontinued Operations	**2,993**	(168)	(243)
Total Investing Activities	**(12,866)**	(1,079)	888
Net Cash Provided (Used) Before Financing Activities	**(9,807)**	(218)	2,362
Financing Activities	**6,515**	(168)	894
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency	**182**	1	(34)
Increase (Decrease) in Cash and Cash Equivalents	**(3,110)**	(385)	3,222

As at December 31,	2017	2016	2015
Cash and Cash Equivalents	**610**	3,720	4,105
Committed and Undrawn Credit Facility	**4,500**	4,000	4,000

Cash From (Used In) Operating Activities

Cash From Operating Activities increased in 2017 mainly due to higher Operating Margin, as discussed in the Financial Results section of this MD&A. Excluding risk management assets and liabilities, assets and liabilities held for sale, and the current portion of the contingent payment, our working capital was $1,133 million at December 31, 2017 compared with $4,423 million at December 31, 2016. Working capital declined primarily due to the use of cash and cash equivalents to fund the Acquisition.

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

Cash From (Used In) Investing Activities

In 2017, the increase in cash used in investing activities was primarily due to the Acquisition and an increase in capital investment, partially offset by $3.2 billion in proceeds from the divestiture of our legacy Conventional assets. In 2016, capital investment was limited due to spending reductions in response to the low commodity price environment.

Cash From (Used In) Financing Activities

Cash from financing activities increased in 2017 primarily due to the issuance of debt and common shares to help finance the Acquisition.

Total debt as at December 31, 2017 was $9,513 million (December 31, 2016 – $6,332 million), with no principal payments due until October 15, 2019 (US$1.3 billion). The increase in total debt is primarily due to the Acquisition financing.

As at December 31, 2017, we were in compliance with all of the terms of our debt agreements.

Senior Unsecured Notes

In connection with the Acquisition, we completed an offering in the U.S. on April 7, 2017 for US$2.9 billion of senior unsecured notes issued in three tranches, US$1.2 billion 4.25 percent senior unsecured notes due April 2027, US$700 million 5.25 percent senior unsecured notes due June 2037, and US$1.0 billion 5.40 percent senior unsecured notes due June 2047 (collectively, the "2017 Notes"). In the fourth quarter of 2017, we completed an exchange offer ("Exchange Offering") whereby substantially all of the 2017 Notes were exchanged for notes registered under the U.S. Securities Act of 1933 with essentially the same terms and provisions as the 2017 Notes.

Committed Bridge Facility

On May 17, 2017, concurrent with the close of the Acquisition, we borrowed $3.6 billion under a committed Bridge Facility. The committed Bridge Facility was repaid in full, using the proceeds from divestiture of our legacy Conventional assets as well as cash on hand, and retired prior to December 31, 2017.

Common Shares

In connection with the Acquisition, on April 6, 2017, Cenovus closed a bought-deal common share offering for 187.5 million common shares for gross proceeds of $3.0 billion.

Dividends

In 2017, we paid dividends of $0.20 per share or $225 million (2016 – $0.20 per share or $166 million). The declaration of dividends is at the sole discretion of the Board and is considered quarterly.

Available Sources of Liquidity

We expect cash flows from our liquids, natural gas and refining operations to fund all of our cash requirements in 2018. Any potential shortfalls may be required to be funded through prudent use of our balance sheet capacity, management of our asset portfolio and other corporate and financial opportunities that may be available to us. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, DBRS Limited and Fitch Ratings.

The following sources of liquidity are available at December 31, 2017:

($ millions)	Term	Amount
Cash and Cash Equivalents	**Not applicable**	**610**
Committed Credit Facility – Tranche A	**November 2021**	**3,300**
Committed Credit Facility – Tranche B	**November 2020**	**1,200**

Committed Credit Facility

On April 28, 2017, we amended our existing committed credit facility to increase the capacity by $0.5 billion to $4.5 billion and to extend the maturity dates. The committed credit facility consists of a $1.2 billion tranche maturing on November 30, 2020 and $3.3 billion tranche maturing on November 30, 2021. As of December 31, 2017, no amounts were drawn on our committed credit facility.

Under the committed credit facility, Cenovus is required to maintain a debt to capitalization ratio not to exceed 65 percent; we are well below this limit.

Base Shelf Prospectus

On October 10, 2017, we filed a base shelf prospectus that allows us to offer, from time to time, up to US$7.5 billion, or the equivalent in other currencies, of debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere, where permitted by law. The base shelf prospectus is available to ConocoPhillips to offer, should they so choose from time to time, the common shares they acquired in connection with the Acquisition. The base shelf prospectus will expire in November 2019 and replaced our US$5.0 billion base shelf prospectus, which would have expired in March 2018. Offerings under the base shelf prospectus are subject to market conditions.

Following the completion of the Exchange Offering and as at December 31, 2017, US$4.6 billion remains available under the 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. We define Capitalization as Net Debt plus Shareholders' Equity. We define Adjusted EBITDA as net earnings before finance costs, interest income, income tax expense, DD&A, goodwill impairments, asset impairments and reversals, unrealized gains (losses) on risk management, foreign exchange gains (losses), revaluation gain, re-measurement of contingent payment, gains (losses) on divestiture of assets, and other income (loss), net, calculated on a trailing 12-month basis. These measures are used to steward our overall debt position and as measures of our overall financial strength.

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

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

As at December 31,	**2017**	2016	2015
Long-Term Debt	**9,513**	6,332	6,525
Less: Cash and Cash Equivalents	**(610)**	(3,720)	(4,105)
Net Debt	**8,903**	2,612	2,420
Net Earnings (Loss)	**3,366**	(545)	618
Add (Deduct):			
Finance Costs	**725**	492	482
Interest Income	**(62)**	(52)	(28)
Income Tax (Recovery) Expense	**352**	(382)	(81)
DD&A	**2,030**	1,498	2,114
E&E Impairment	**890**	2	138
Unrealized (Gain) Loss on Risk Management	**729**	554	195
Foreign Exchange (Gain) Loss, Net	**(812)**	(198)	1,036
Revaluation Gain	**(2,555)**	-	-
Re-measurement of Contingent Payment	**(138)**	-	-
(Gain) Loss on Discontinuance	**(1,285)**	-	-
(Gain) Loss on Divestiture of Assets	**1**	6	(2,392)
Other (Income) Loss, Net	**(5)**	34	2
Adjusted EBITDA [(1)]	**3,236**	1,409	2,084
Net Debt to Adjusted EBITDA	**2.8x**	1.9x	1.2x

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

Net Debt to Capitalization is calculated as follows:

As at December 31,	**2017**	2016	2015
Net Debt	**8,903**	2,612	2,420
Shareholders' Equity	**19,981**	11,590	12,391
Capitalization	**28,884**	14,202	14,811
Net Debt to Capitalization [(1)]	**31%**	18%	16%

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

As at December 31, 2017, Cenovus's Net Debt to Adjusted EBITDA is 2.8x, which is above our target. However, it is important to note that Adjusted EBITDA is calculated on a trailing 12-month basis and as such, only includes the financial results from the Deep Basin Assets and the additional 50 percent of FCCL for the period May 17, 2017 to December 31, 2017. Net debt is presented as at December 31, 2017; therefore, the ratio is burdened by the debt issued to finance the Acquisition. If Adjusted EBITDA reflected a full twelve months of earnings from the acquired assets, Cenovus's Net Debt to Adjusted EBITDA ratio would be lower. Net Debt to Adjusted EBITDA increased as a result of a higher long-term debt balance, partially offset by higher Adjusted EBITDA due to the rise in sales volumes as a result of the Acquisition and higher commodity prices.

Net Debt to Capitalization increased as a result of the higher long-term debt balance, related to the Acquisition, partially offset by the increase in Shareholders' Equity and the strengthening of the Canadian dollar relative to the U.S. dollar.

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, 2017, there were approximately 1,229 million common shares outstanding (2016 – 833 million common shares). In connection with the Acquisition, Cenovus closed a bought-deal common share financing on April 6, 2017 for 187.5 million common shares, raising gross proceeds of $3.0 billion ($2.9 billion net of $101 million of share issuance costs).

In addition, we issued 208 million common shares to ConocoPhillips on May 17, 2017 as partial consideration for the Acquisition. In relation to the share consideration, Cenovus and ConocoPhillips entered into an investor agreement, and a registration rights agreement which, among other things, restricted ConocoPhillips from selling or hedging its Cenovus common shares until November 17, 2017. ConocoPhillips is also restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with management recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the outstanding common shares of Cenovus. As at December 31, 2017, ConocoPhillips continued to hold these shares.

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

Refer to Note 29 of the Consolidated Financial Statements for more details on our Stock Option Plan and our PSU, RSU and DSU Plans.

As at January 31, 2018	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,228,790**	**N/A**
Stock Options	**42,337**	**35,263**
Other Stock-Based Compensation Plans	**13,963**	**1,439**

Contractual Obligations and Commitments

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

	Expected Payment Date						
($ millions)	2018	2019	2020	2021	2022	Thereafter	**Total**
Operating							
Transportation and Storage (1)	899	886	919	1,123	1,223	13,260	**18,310**
Operating Leases (Building Leases)	155	146	142	141	140	2,305	**3,029**
Other Long-term Commitments	109	39	32	28	25	122	**355**
Interest on Long-term Debt	494	494	402	401	401	5,970	**8,162**
Decommissioning Liabilities	23	41	45	43	35	1,717	**1,904**
Other	11	11	9	5	4	14	**54**
Total Operating	1,691	1,617	1,549	1,741	1,828	23,388	**31,814**
Investing							
Capital Commitments	16	2	-	-	-	-	**18**
Total Investing	16	2	-	-	-	-	**18**
Financing							
Long-term Debt (principal only)	-	1,631	-	-	627	7,339	**9,597**
Other	-	-	1	-	1	2	**4**
Total Financing	-	1,631	1	-	628	7,341	**9,601**
Total Payments (2) (3)	1,707	3,250	1,550	1,741	2,456	30,729	**41,433**

(1) *Includes transportation commitments of $9 billion that are subject to regulatory approval or have been approved but are not yet in service.*
(2) *Contracts on behalf of WRB Refining LP ("WRB") are reflected at our 50 percent interest.*
(3) *Total commitments as at December 31, 2017 includes $29 million related to the Suffield assets that were divested on January 5, 2018.*

Commitments for various pipeline transportation arrangements decreased $8.0 billion from 2016 primarily due to pipeline project cancellations, partially offset by incremental commitments included with the Acquisition and newly executed transportation agreements. Terms are up to 20 years subsequent to the date of commencement.

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

As at December 31, 2017, there were outstanding letters of credit aggregating $376 million issued as security for performance under certain contracts (December 31, 2016 – $258 million).

Legal Proceedings

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

Contingent Payment

In connection with the Acquisition and related to oil sands production, we agreed to make quarterly payments to ConocoPhillips during the five years subsequent to May 17, 2017 for quarters in which the average WCS crude oil price exceeds $52 per barrel during the quarter. As at December 31, 2017, the estimated fair value of the contingent payment was $206 million. WCS averaged above $52 per barrel in the fourth quarter of 2017; therefore, $17 million is payable under this agreement. The calculation includes an adjustment mechanism related to certain significant production outages at Foster Creek and Christina Lake, which may reduce the amount of a contingent payment. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

See the Corporate and Eliminations section of this MD&A for more details.

RISK MANAGEMENT AND RISK FACTORS

Cenovus is exposed to a number of risks through the pursuit of our strategic objectives. Some of these risks impact the oil and gas industry as a whole and others are unique to our operations. The impact of any risk or a combination of risks may adversely affect, among other things, Cenovus's business, reputation, financial condition, results of operations and cash flows, which may reduce or restrict our ability to pay a dividend to our shareholders and may materially affect the market price of our securities.

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

Risk Governance

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

Risk Assessment

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

Significant Risk Factors

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

Financial Risk

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

Commodity Prices

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

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

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

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

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

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

Development and Operating Costs

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

Hedging Activities

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

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

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

We partially mitigate our exposure to commodity price risk through the integration of our business, financial instruments, physical contracts and market access commitments. Financial instruments utilized within the refining business are primarily for purchased product. For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 3 and 33 to the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

	2017			2016		
($ millions)	**Realized**	**Unrealized**	**Total**	Realized	Unrealized	Total
Crude Oil [(1)]	**307**	**716**	**1,023**	(152)	560	408
Refining	**6**	**-**	**6**	(1)	5	4
Power	**-**	**-**	**-**	-	(14)	(14)
Interest Rate	**-**	**13**	**13**	-	3	3
Foreign Exchange	**(146)**	**-**	**(146)**	-	-	-
(Gain) Loss on Risk Management	**167**	**729**	**896**	(153)	554	401
Income Tax Expense (Recovery)	**(60)**	**(197)**	**(257)**	39	(150)	(111)
(Gain) Loss on Risk Management, After Tax	**107**	**532**	**639**	(114)	404	290

(1) *Excludes $33 million of realized risk management losses on crude oil contracts from our Conventional segment (2016 – $58 million realized risk management gains), which has been classified as a discontinued operation.*

In 2017, we incurred realized losses on crude oil risk management activities, consistent with the average benchmark prices exceeding our contract prices and realized gains on foreign exchange contracts primarily due to hedging activity undertaken to support the Acquisition. Unrealized losses were recorded on our crude oil financial instruments in 2017 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 and interest rates with all other variables held constant. Management believes the price fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuations in commodity prices and interest rates on risk management positions as at December 31, 2017 could have resulted in unrealized gains (losses) for the year as follows:

	Sensitivity Range	**Increase**	**Decrease**
Crude Oil Commodity Price	± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	**(529)**	**507**
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	**11**	**(11)**
Interest Rate Swaps	± 50 Basis Points	**44**	**(50)**

For further information on our risk management positions, see Note 34 to the Consolidated Financial Statements.

Risks Associated with Derivative Financial Instruments

Financial instruments expose Cenovus to the risk that a counterparty will default on its contractual obligations. This risk is partially mitigated through credit exposure limits, frequent assessment of counterparty credit ratings and netting arrangements, as outlined in our Credit Policy.

Exposure to Counterparties

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

Credit, Liquidity and Availability of Future Financing

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

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

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

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

Credit Ratings

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

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

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

To manage exposure to exchange rate fluctuations, we may periodically enter into transactions to mitigate our exposure. 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.

Ability to Pay Dividends

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

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

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

Operational Risk

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

Health and Safety

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

Market Access Constraints and Transportation Restrictions

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

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

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

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

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

Operational Considerations

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

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

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

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

Reserves Replacement and Reserve Estimates

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

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and the future net cash flows and revenue derived therefrom are based on a number of variable factors and assumptions including, but not limited to: product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including 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.

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; risks relating to schedule, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of general economic, business and market conditions; the impact of weather conditions; risk related to the accuracy of project cost estimates; ability to finance growth; ability to source or complete strategic transactions; and the effect of changing government regulation and public expectations in relation to the impact of oil sands and conventional development on the environment. The commissioning and integration of new facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could have a material adverse effect on our financial condition, results of operations and cash flows.

Partner Risks

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

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

Technology

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

Information Systems

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

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

Leadership and Talent

Our success is dependent upon our Management, our leadership capabilities and the quality and competency of our talent. In 2017, Cenovus implemented a number of changes at the executive leadership level, including the appointment of Alex Pourbaix as President & Chief Executive Officer and as a member of the Board. We believe that these leadership changes will help Cenovus continue to evolve into a highly effective organization focused on delivering strong returns for shareholders. Failure to align and effectively integrate the new leadership team, retain critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies could have a material adverse effect on our financial condition, results of operations and pace of growth.

Litigation

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

Aboriginal Land and Rights Claims

Aboriginal groups have claimed aboriginal treaty, title and rights to portions of western Canada, including British Columbia and Alberta, and such claims, if successful, could have a material negative impact on our operations or pace of growth. In 2014, the Supreme Court of Canada granted Aboriginal title over non-treaty lands, representing the first instance of such a declaration. There exist outstanding Aboriginal and treaty rights claims, which may include Aboriginal title claims, on lands where we operate. No certainty exists that any lands currently unaffected by claims brought by Aboriginal groups will remain unaffected by future claims. Recent outcomes of litigation concerning Aboriginal rights may result in increased claims and litigation activity in the future.

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

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

Regulatory Risk

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

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

Regulatory Approvals

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

Failure to obtain applicable regulatory approvals or satisfy any of the conditions thereto on a timely basis on satisfactory terms could result in delays, abandonment or restructuring of projects and increased costs.

Abandonment and Reclamation Cost Risk

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

The Alberta Court of Queen's Bench issued a decision in the case of Redwater Energy Corporation, ("Redwater") that trustees and receivers of insolvent parties may disclaim or renounce uneconomic oil and gas assets to the AER before commencing the sales process for the insolvent party's assets. These wells and facilities then become "orphans" to be remediated by the OWA. The Alberta Court of Appeal upheld the trial judge's decision in Redwater ("Redwater Appeal"), and the AER has been granted leave to appeal the Redwater Appeal to the Supreme Court of Canada.

In response to Redwater, 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.* Among other things, *Directive 067* provides the AER with broad discretion to determine if a party poses an "unreasonable risk" such that they should not be eligible to hold AER licences.

The government of British Columbia has announced similar policies. The British Columbia Oil and Gas Commission is also exploring the development of a comprehensive liability management strategy, driven in part by the Redwater decision, and the proliferation of orphan sites. The imposition of timelines for inactive sites is among the measures under consideration.

These changes may impact Cenovus's ability to transfer our licences, approvals or permits, and may result in increased costs and delays or require changes to or abandonment of projects and transactions. Because of Redwater and the current economic environment, the number of orphaned wells in Alberta has increased significantly and, accordingly, the aggregate value of the A&R liabilities assumed by the OWA has increased and may continue to increase. The OWA may seek 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 as a result of the Redwater decision and its pending appeal cannot be reliably or accurately estimated, any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

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

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

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

Environmental Regulatory Risk

All phases of crude oil, natural gas and refining operations are subject to environmental regulation pursuant to a variety of Canadian and U.S. federal, provincial, territorial, state and municipal laws and regulations (collectively, the "environmental regulations"). Environmental regulations provide that wells, facility sites, refineries and other properties and practices associated with our operations be constructed, operated, maintained, abandoned, reclaimed and undertaken in accordance with the requirements set out therein. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, 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 can require significant expenditures, including costs and damages arising from releases or contaminated properties or spills, or from new compliance obligations. We anticipate that future capital expenditures and operating expenses could continue to increase as a result of the implementation of new environmental regulations. Failure to comply with environmental regulations may result in the imposition of fines, penalties, environmental protection orders, suspension of operations, and could adversely impact our reputation. The costs of complying with environmental regulations may have a material adverse effect on our business, financial condition, results of operations and cash flows. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the crude oil and natural gas industry generally could reduce demand for crude oil and natural gas and increase compliance costs, and have an adverse impact on our business, financial condition, results of operations and cash flows. There is also risk that we could face litigation initiated by third parties relating to climate change or other environmental regulations.

Climate Change Regulation

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

In 2016, the Government of Canada ratified the international Paris Agreement on climate change and announced a new national carbon pricing regime (the "Carbon Strategy"). All Canadian provinces and territories except Saskatchewan and Manitoba signed the pan-Canadian framework to implement the Carbon Strategy. In 2018, the Federal Government released the draft *Greenhouse Gas Pollution Pricing Act* under the Carbon Strategy, which specifies (i) a carbon price on fossil fuels of $10 per tonne of carbon dioxide equivalent ("CO2e") in 2018, rising by $10 per year to $50 per tonne CO2e in 2022 and (ii) an Output-Based Pricing System ("OBPS") for industrial facilities with annual emissions of 50 kilotonnes of GHG per year or more. OBPS facilities will be subject to the carbon price on the portion of emissions that exceed an annual output-based emissions limit, which can be satisfied by paying a charge, applying federally issued surplus credits or eligible offset credits. The design of this system is currently under development.

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

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

The British Columbia *Carbon Tax Act* sets a carbon price of $30 per tonne of CO2e on fuel combustion. Beginning April 1, 2018, the provincial carbon tax is expected to increase by $5 per tonne of CO2e per year, reaching the federal target carbon price of $50 on April 1, 2021. The tax may also be expanded to fugitive and vented emissions from the oil and gas sector. The British Columbia government has signalled further measures, such as reducing upstream methane emissions by 45 percent and may establish separate sectoral reduction goals and plans. The government has also indicated their intention to work with emissions intensive industries to maintain their competitiveness. Further details have not yet been announced.

In 2017, the federal government also proposed regulations to limit the release of methane and volatile organic compounds with staged implementation over the 2020 to 2023 time period. Provinces may establish their own methane reduction regulations and set up equivalency agreements with the federal government. Alberta is developing methane reduction rules that are expected to align with the federal government's proposed regulations.

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

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

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

Cenovus's analysis suggests that we will remain financially resilient over the long-term under a range of climate policy scenarios. However, the extent and magnitude of any adverse impacts of additional programs or regulations beyond reasonably foreseeable requirements cannot be reliably or accurately estimated at this time 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.

Low Carbon Fuel Standards

Existing and proposed environmental legislation 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.

On December 13, 2017, Environment and Climate Change Canada published a regulatory framework on its proposed clean fuel standard regulation to be adopted under the *Canadian Environmental Protection Act, 1999*. The federal government is expected to release draft regulations in 2018. The clean fuel standard regulation will establish lifecycle carbon intensity requirements separately for liquid, gaseous and solid fuels that are used in transportation, industry and buildings. The stated purpose of the clean fuel standard is to incent the use of a broad range of low carbon fuels, energy sources and technologies. The clean fuel standard will apply to liquid, gaseous and solid fuels combusted for the purpose of creating energy, including "self-produced and used" fuels (i.e., those fuels that are used by producers or importers). The clean fuel standard regulation has the potential to impact our business, financial condition, results of operations and cash flows, though at this time it is difficult to predict or quantify any such impacts.

The state of California and the province of British Columbia have implemented climate change regulation in the form of a Low Carbon Fuel Standard and the Renewable and Low Carbon Fuel Requirements Regulation, respectively. The regulations require the reduction of life cycle carbon emissions from transportation fuels. As an oil sands producer, we are not directly regulated and are not expected to have a compliance obligation. Refiners in California and British Columbia are required to comply with the legislation.

Renewable Fuel Standards

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

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

Marine Fuel Oil Sulphur Specification

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

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

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

Alberta's Land-Use Framework

Alberta's Land-Use Framework has been implemented under the *Alberta Land Stewardship Act* ("ALSA") which sets out the Government of Alberta's approach to managing Alberta's land and natural resources to achieve long-term economic, environmental and social goals. In some cases, ALSA amends or extinguishes previously issued consents such as regulatory permits, licences, approvals and authorizations in order to achieve or maintain an objective or policy resulting from the implementation of a regional plan.

The Government of Alberta has implemented the Lower Athabasca Regional Plan ("LARP"), under the ALSA. The LARP identifies legally-binding management frameworks, including for air, land and water, which will incorporate cumulative limits and triggers as well as identifying areas related to conservation, tourism and recreation. Uncertainty exists with respect to the impact to future development applications in the areas covered by the LARP, including the potential for development restrictions and mineral rights cancellation.

The Government of Alberta has also implemented the South Saskatchewan Regional Plan ("SSRP") and has commenced the regional planning process for the North Saskatchewan Regional Plan ("NSRP") under the ALSA. SSRP is not expected to materially impact Cenovus's existing operations, but may impact any future development Cenovus may undertake within the region. No assurance can be given that the NSRP, or any future regional plans developed and implemented by the Government of Alberta, will not materially impact operations or future operations in their applicable regions.

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 in areas identified as critical habitat for species of concern, such as woodland caribou. Recent litigation against the federal government in relation to the *Species at Risk Act* has raised issues associated with the protection of species at risk and their critical habitat both federally and on a provincial level. In Alberta, the Alberta Caribou Action and Range Planning Project has been established to develop range plans and action plans with a view to achieving the maintenance and recovery of Alberta's 15 caribou populations. Similar planning has been undertaken in British Columbia by the Ministry of Environment and the Ministry of Forests, Lands, and Natural Resource Operations.

In 2017, the British Columbia government released its Draft Boreal Caribou Recovery Implementation Plan for comment, and the Alberta government released its Draft Provincial Woodland Caribou Range Plan for comment. Both draft plans focus largely on reduction of linear features, such as seismic lines. If action and range plans developed by the provinces are deemed not to provide sufficient likelihood of caribou recovery, the federal legislation includes the ability to implement measures that would preclude further development or modify existing operations. The federal and/or provincial implementation of measures to protect species at risk such as woodland caribou and their critical habitat in areas of Cenovus's current or future operations may modify our pace and amount of development.

Federal Air Quality Management System

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

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

Federal Review of Environmental and Regulatory Processes

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

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

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

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

The proposed amendments are subject to change as they work through the Parliamentary process. The extent and magnitude of any adverse impacts of changes to the legislation or programs on project development and operations cannot be reliably or accurately estimated at this time as uncertainty exists with respect to how the legislative changes that will be implemented and what the accompanying regulations, including the designated project list, will look like. Increased environmental assessment obligations and reporting obligations may create risk of increased costs and project development delays.

British Columbia Review of Environmental and Regulatory Processes

In 2017, the Government of British Columbia committed to reviewing the province's environmental assessment process and other regulatory processes, including enacting an endangered species law and harmonizing other laws related to the environment. The government has commenced a review into the adequacy and oversight of professional reliance model employed in the natural resource sector and has introduced regulations requiring spill preparedness for transporters of liquid petroleum products in British Columbia. The government has also reaffirmed their commitment to proceed with a scientific review of hydraulic fracturing to determine impacts on water and the relationship to seismic activity.

The Government of British Columbia has proposed regulations relating to liquid petroleum spill response and recovery. The proposed regulations include regulating spill response times, compensation for loss of public and cultural use of land, resources or public amenities in the case of spills, and creating geographic response plans in certain areas. The government will also establish an independent scientific advisory panel to recommend whether, and how, heavy oils (such as bitumen) can be safely transported and cleaned up. As noted, while the advisory panel is proceeding, the government is proposing regulatory restrictions on the increase of diluted bitumen transportation.

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

Water Licences

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

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

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

Alberta Wetland Policy

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

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

The Alberta Wetland Policy is not expected to affect Cenovus's existing operations in Foster Creek, Christina Lake and Narrows Lake, where our 10 year wetlands mitigation and monitoring plans were approved under the previous wetland policy. However, new project developments and future phase expansions will likely be affected by aspects of this policy as our oil sands leases are in areas where wetlands cover over 50 percent of the landscape. Development of some projects within our Deep Basin asset near wetland regions will also be affected by the policy. 'Avoidance' may not be an option for new projects, developments and phase expansions. We expect to be required to comply with requirements for wetland reclamation or, where permanent wetland loss will occur, wetland replacement. In accordance with the *Alberta Wetland Restoration Directive, 2016*, mechanisms for restorative replacement include purchase of credits (under development), payment to an in-lieu fee program, or permittee-responsible replacement action.

Based on written statements in the *Alberta Wetland Mitigation Directive, 2016* and consultation with Alberta Environment and Parks as well as the AER, we do not anticipate a material impact on our oil sands or unconventional assets in the Deep Basin. However, it remains unclear how the policy will be implemented and no assurance can be given that the policy will not have an impact on future development plans at this time.

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.

Oil and Gas Activities Act

In British Columbia, the *Oil and Gas Activities Act* (the "OGAA") impacts conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "Commission") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for Crown lands, water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not exclusively an environmental statute, the *Petroleum and Natural Gas Act*, in conjunction with the OGAA, requires companies to obtain various approvals before undertaking exploration or production work, such as geophysical licenses, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licenses and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Reputation Risk

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

Public Perception of Alberta Oil Sands

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

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

Other Risks

Risks Related to the Acquisition

Unexpected Costs or Liabilities Related to the Acquisition

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

Although we conducted title and environmental reviews in respect of the Deep Basin assets, which include approximately three million net acres of land containing liquids rich natural gas, condensate and other NGLs, and light and medium oil located primarily in the Elmworth-Wapiti, Kaybob-Edson and Clearwater operating areas and include interests in numerous natural gas processing facilities, such reviews cannot guarantee that any unforeseen defects in the chain of title will not arise to defeat our title to certain assets or that environmental defects or deficiencies do not exist.

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

Realization of Acquisition Benefits

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

Amount of Contingent Payments

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

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

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

Tax Laws

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

United States Tax Risk

In the U.S., the *Tax Cuts and Jobs Act* was signed into law on December 22, 2017. The new legislation: reduces the federal corporate tax rate from 35 percent to 21 percent; allows immediate expensing of qualified property acquired prior to 2023; imposes a limitation on the utilization of net operating losses to 80 percent of taxable income; sets a limitation on the deductibility of interest expense; and introduces new provisions imposing a minimum tax in certain circumstances when a company has payments to a related foreign entity. There are currently significant gaps in the legislation that will reportedly be supplemented with regulations. Accordingly, there is significant uncertainty with respect to the interpretation and implementation of the legislation. There is also potential for some or all of the changes to be revised or reversed if there is a change in governing party. We expect there will be impacts to Cenovus in terms of the U.S. taxes paid by us, but it is difficult to estimate the potential magnitude and timing of impacts to Cenovus due to the uncertainties noted with respect to the *Tax Cuts and Jobs Act*.

United States Trade Risk relating to NAFTA Renegotiation

The outcome of the ongoing renegotiation of the North American Free Trade Agreement ("NAFTA") could include significant changes to, or U.S. withdrawal from, the treaty. While Cenovus is not aware of any proposals in the renegotiation to materially alter the terms of trade for energy resources, if the outcome of the renegotiation did include any such changes, or if the U.S. were to withdraw from the NAFTA and adopt discriminatory or other measures adversely affecting the sale or transportation of our products in the U.S., this could have a significant negative impact on our financial condition or results from operations.

Arrangement Related Risk

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

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

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, and use judgment in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our critical accounting policies and estimates are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our significant accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in our Consolidated Financial Statements.

Joint Arrangements

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

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

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

- The intention of the transaction creating FCCL and WRB was to form an integrated North American heavy oil business. The integrated business was structured, initially on a tax neutral basis, through two partnerships due to the assets residing in different tax jurisdictions. Partnerships are "flow-through" entities which have a limited life.
- The partnership agreements require the partners (Cenovus and ConocoPhillips or Phillips 66 or respective subsidiaries) to make contributions if funds are insufficient to meet the obligations or liabilities of the partnerships. The past and future development of FCCL and WRB is dependent on funding from the partners by way of partnership notes payable and loans. The partnerships do not have any third-party borrowings.
- FCCL operates like most typical western Canadian working interest relationships where the operating partner takes product on behalf of the participants. WRB has a very similar structure modified only to account for the operating environment of the refining business.
- Cenovus and Phillips 66, as operators, either directly or through wholly-owned subsidiaries, provide marketing services, purchase necessary feedstock, and arrange for transportation and storage on the partners' behalf as the agreements prohibit the partnerships from undertaking these roles themselves. In addition, the partnerships do not have employees and, as such, are not capable of performing these roles.
- In each arrangement, output is taken by one of the partners, indicating that the partners have rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangements.

Exploration and Evaluation Assets

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

Identification of CGUs

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

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period 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 and DD&A expense of our crude oil and natural gas assets in the Oil Sands and Deep Basin segments. Cenovus's crude oil and natural gas reserves are evaluated annually and reported to Cenovus by our IQREs. Refer to the Outlook section of this MD&A for more details on future commodity prices.

Recoverable Amounts

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

As at December 31, 2017, the recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs. Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2017 by our IQREs.

Crude Oil and Natural Gas Prices

The forward prices as at December 31, 2017, used to determine future cash flows from crude oil and natural gas reserves were:

	2018	2019	2020	2021	2022	Average Annual Increase Thereafter
WTI (US$/barrel)	57.50	60.90	64.13	68.33	71.19	2.1%
WCS (C$/barrel)	50.61	56.59	60.86	64.56	66.63	2.1%
Edmonton C5+ (C$/barrel)	72.41	74.90	77.07	81.07	83.32	2.1%
AECO (C$/Mcf) [1]	2.43	2.77	3.19	3.48	3.67	2.0%

(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, which is common industry practice and used by Cenovus's IQREs in preparing their reserves reports.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of our upstream crude oil and natural gas assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence and to estimate the future liability. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors. Refer to Note 24 of the Consolidated Financial Statements for more details on changes to decommissioning costs.

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

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

Income Tax Provisions

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

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

Recent Accounting Pronouncements

There were no new or amended accounting standards or interpretations adopted during 2017.

New Accounting Standards and Interpretations not yet Adopted

A number of new accounting standards, amendments to accounting standards and interpretations are effective for annual periods beginning on or after January 1, 2018 and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2017. The standards applicable to Cenovus are as follows and will be adopted on their respective effective dates:

Financial Instruments

On July 24, 2014, the IASB issued the final version of IFRS 9, "*Financial Instruments*" ("IFRS 9") to replace IAS 39, "*Financial Instruments: Recognition and Measurement*" ("IAS 39").

IFRS 9 introduces a single approach to determine whether a financial asset is measured at amortized cost or fair value and replaces the multiple rules in IAS 39. The approach is based on how an entity manages its financial instruments in the context of its business model and the contractual cash flow characteristics of the financial assets. The IAS 39 measurement categories for financial assets will be replaced by fair value through profit or loss, fair value through other comprehensive income ("FVOCI") and amortized cost. The standard eliminates the existing IAS 39 categories of held to maturity, loans and receivables and available for sale. Based on Management's assessment, the change in categories will not have a material impact on the Consolidated Financial Statements. As at December 31, 2017, the Company has private equity investments classified as available for sale with a fair value of $37 million. Under IFRS 9, we have elected to measure these investments as FVOCI. As such, all fair value gains or losses will be recorded in other comprehensive income ("OCI"), impairments will not be recognized in net earnings and fair value gains or losses will not be recycled to net earnings on disposition.

IFRS 9 retains most of the IAS 39 requirements for financial liabilities. However, where the fair value option is applied to financial liabilities, the change in fair value resulting from an entity's own credit risk is recorded in OCI rather than net earnings, unless this creates an accounting mismatch. Cenovus currently does not designate any financial liabilities as fair value through profit or loss; therefore, there will be no impact on the accounting for financial liabilities.

A new expected credit loss model for calculating impairment on financial assets replaces the incurred loss impairment model used in IAS 39. The new model will result in more timely recognition of expected credit losses. Based on Management's assessment, no additional impairment loss is expected as at January 1, 2018, the date of adoption.

In addition, IFRS 9 includes a simplified hedge accounting model, aligning hedge accounting more closely with risk management. Cenovus does not currently apply hedge accounting.

IFRS 9 must be adopted for years beginning on or after January 1, 2018. We will apply the new standard retrospectively and elect to use the practical expedients permitted under the standard. Comparative periods will not be restated.

Revenue Recognition

On May 28, 2014, the IASB issued IFRS 15, "*Revenue From Contracts With Customers*" ("IFRS 15") replacing IAS 11, "*Construction Contracts*", IAS 18, "*Revenue*" and several revenue-related interpretations. IFRS 15 establishes a single revenue recognition framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of goods and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded.

Management has assessed the impact of applying the new standard on the Consolidated Financial Statements and has not identified any material differences from its current revenue recognition practice.

The adoption of IFRS 15 is mandatory for years beginning on or after January 1, 2018. The standard may be applied either retrospectively or using a modified retrospective approach. We intend to adopt the standard using the modified retrospective approach recognizing the cumulative impact of adoption in retained earnings as of January 1, 2018. Comparative periods will not be restated. We will apply IFRS 15 using the practical expedient in paragraph C5(a) of IFRS 15, under which the Company will not restate contracts that are completed contracts as at the date of adoption.

Leases

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

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

IFRS 16 is effective for years beginning on or after January 1, 2019, with early adoption permitted if IFRS 15 has been adopted. The standard may be applied retrospectively or using a modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of applying the standard to prior periods as an adjustment to opening retained earnings. It is anticipated that the adoption of IFRS 16 will have a material impact on our Consolidated Balance Sheets due to material operating lease commitments as disclosed in Note 36 of the Consolidated Financial Statements. Cenovus will adopt IFRS 16 effective January 1, 2019. We intend to adopt the standard using the retrospective with cumulative effect approach and apply several of the practical expedients available.

Uncertain Tax Positions

In June 2017, the IASB issued International Financial Reporting Interpretation Committee ("IFRIC") 23, *"Uncertainty over Income Tax Treatments"*. The interpretation provides clarity on how to account for a tax position when there is uncertainty over income tax treatments. In determining the likely resolution of the uncertain tax positions, a position may be considered separately or as a group. In addition, an assessment is required to determine the probability that the tax authority will accept the tax position taken in income tax filings. If the uncertain income tax treatment is unlikely to be accepted, the accounting tax position must reflect an appropriate level of uncertainty. An uncertain tax position may be reassessed if new information changes the original assessment. IFRIC 23 is effective for annual periods beginning on or after January 1, 2019 using either a modified or full retrospective approach. IFRIC 23 is not expected to have a significant impact on the Consolidated Financial Statements.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of internal control over financial reporting ("ICFR") and disclosure controls and procedures ("DC&P") as at December 31, 2017. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2017.

Management excluded the Deep Basin assets from its assessment of internal control over financial reporting as at December 31, 2017 because they were acquired by the Company through a business combination in 2017. As permitted by and in accordance with, National Instrument 52-109, "*Certification of Disclosure in Issuers' Annual and Interim Filings*", and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures of the Deep Basin Assets. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to the Deep Basin Assets in a manner consistent with our other operations.

Summary financial information related to the Deep Basin Assets included in the Consolidated Financial Statements is as follows:

($ millions)	May 17 - December 31, 2017
Revenues	514
Operating Margin	207
Net Earnings (Loss)	(108)

As at	December 31, 2017
Current Assets	619
Non-Current Assets	6,075
Current Liabilities	364
Non-Current Liabilities	496

In addition, we acquired Deep Basin commitments of approximately $500 million, primarily consisting of transportation commitments on various pipelines.

The effectiveness of our ICFR, which excludes the Deep Basin assets, was audited as at December 31, 2017 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, 2017.

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

CORPORATE RESPONSIBILITY

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

We published our 2016 CR report in July 2017 to report on our management efforts and performance across the above noted areas within our CR policy, as well as other environment, social and governance topics that are important to our stakeholders. Our CR report also lists external recognition we received for our commitment to corporate responsibility, and is available on our website at cenovus.com.

OUTLOOK

We will continue to look for ways to increase our margins through strong operating performance and cost leadership, while delivering safe and reliable operations. Proactively managing our market access commitments and opportunities should assist with our goal of reaching a broader customer base to secure a higher sales price for our liquids production.

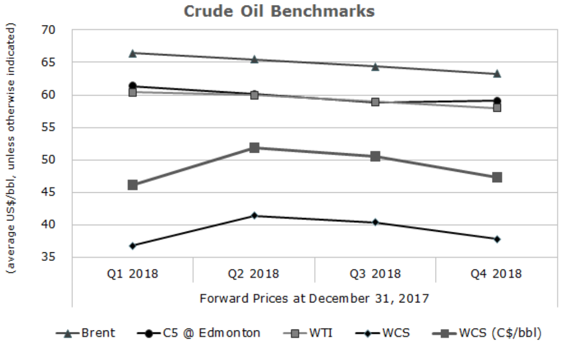
We have reduced the amount of capital needed to sustain our base business and expand our projects, which we believe will help to ensure our financial resilience.

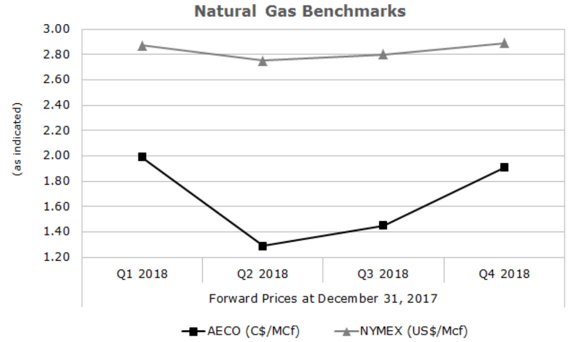
The following outlook commentary is focused on the next twelve months.

Commodity Prices Underlying our Financial Results

Our crude oil pricing outlook is influenced by the following:

- We expect the general outlook for crude oil prices will be tied primarily to the supply response to the current price environment, the impact of potential supply disruptions, and the pace of growth in global demand as influenced by macro-economic events. Overall, we expect crude oil price volatility to continue and a modest price improvement in the next twelve months. OPEC’s ability to adhere to its current production cuts and the possibility of future production cuts, combined with annual increases in demand growth should support prices, constrained by the need to draw down surplus crude oil inventories and U.S. production growth;
- We anticipate the Brent-WTI differential will narrow after the impacts of severe weather related incidents dissipate and as a result of the U.S. exporting crude oil to overseas markets. Overall, the differential will likely be set by transportation costs; and
- We expect that the WTI-WCS differential will widen due to Canadian supply increasing due to the resolution of production outages, oil sands supply growth and transportation constraints, partially offset by the possibility of OPEC extending production cuts.

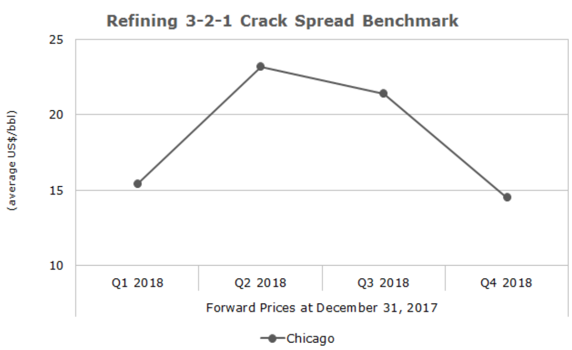


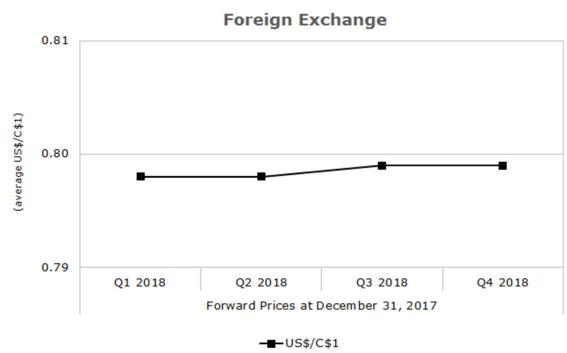


Natural gas prices are anticipated to improve in the first quarter of 2018 with a normal winter heating season and increased U.S. natural gas exports, partially offset by expected North American natural gas supply growth. However, mild weather occurred in the first few months of winter in 2017. If these trends continue, it will put downward pressure on prices.

Seasonal demand changes and refinery maintenance activity will result in fluctuations of refining crack spreads throughout 2018. The impact of potentially weaker refining crack spreads on refinery margins will be partially offset by the widening of the WTI-WCS differential, which increases the refinery feedstock cost advantage.

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





Our exposure to the light/heavy price differentials is composed of both a global light/heavy component as well as Canadian transportation constraints. While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of swings in light/heavy price differentials through the following:

- Integration – having heavy oil refining capacity capable of processing Canadian heavy oil. From a value perspective, our refining business positions us to capture value from both the WTI-WCS differential for Canadian crude oil and the Brent-WTI differential from the sale of refined products;
- Financial hedge transactions – limiting the impact of fluctuations in upstream crude oil prices by entering into financial transactions that fix the WTI-WCS differential;
- Marketing arrangements – limiting the impact of fluctuations in upstream crude oil prices by entering into physical supply transactions with fixed price components directly with refiners; and
- Transportation commitments and arrangements – supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets.

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

Key Priorities for 2018

Cost Reductions and Deleveraging

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

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

We are making some significant reductions to our non-rent general and administrative costs in 2018, the majority of which will come from workforce reductions, which we expect to be substantially completed by the end of the first quarter of 2018.

At December 31, 2017, through a combination of cash on hand and available capacity on our committed credit facility, we have approximately $5.1 billion of liquidity. We are currently marketing a package of non-core Deep Basin assets with production of approximately 15,000 BOE per day. We believe our liquidity position, proceeds from the asset sale and further cost reductions will help us reach our Net Debt to Adjusted EBITDA target of less than 2.0 times.

Disciplined Capital Investment

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

Market Access

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

ADVISORY

Oil and Gas Information

The estimates of reserves were prepared effective December 31, 2017 by independent qualified reserves evaluators, based on the Canadian Oil and Gas Evaluation Handbook and in compliance with the requirements of National Instrument 51-101, *Standards of Disclosure for Oil and Gas Activities*. Estimates are presented using an average of three IQRE's January 1, 2018 price forecast. For additional information about our reserves and other oil and gas information, see "Reserves Data and Other Oil and Gas Information" in our AIF for the year ended December 31, 2017.

Barrels of Oil Equivalent – natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of six Mcf to one barrel (bbl). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Forward-looking Information

This document contains certain forward-looking statements and forward-looking information (collectively referred to as "forward-looking information") within the meaning of applicable securities legislation, including the U.S. *Private Securities Litigation Reform Act of 1995*, about our current expectations, estimates and projections about the future, based on certain assumptions made by us in light of our experience and perception of historical trends. Although we believe that the expectations represented by such forward looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

Forward-looking information in this document is identified by words such as "anticipate", "believe", "expect", "estimate", "plan", "forecast", "future", "target", "position", "project", "committed", "can be", "pursue", "capacity", "could", "should", "will", "focus", "outlook", "potential", "priority", "may", "strategy", "forward", or similar expressions and includes suggestions of future outcomes, including statements about: our strategy and related milestones and schedules, including expected timing for oil sands expansion phases and associated expected production capacities; projections for 2018 and future years and our plans and strategies to realize such projections; forecast exchange rates and trends; our future opportunities for oil development; forecast operating and financial results, including forecast sales prices, costs and cash flows; targets for our Net Debt to Capitalization and Net Debt to Adjusted EBITDA ratios; our ability to satisfy payment obligations as they become due; priorities for our capital investment decisions; planned capital expenditures, including the amount, timing and financing thereof; expected future production, including the timing, stability or growth thereof; expected reserves; capacities, including for projects, transportation and refining; our ability to preserve our financial resilience and various plans and strategies with respect thereto; forecast cost savings and sustainability thereof; our priorities for 2018; future impact of regulatory measures; forecast commodity prices, differentials and trends and expected impact to Cenovus; potential impacts to Cenovus of various risks, including those related to commodity prices and the Acquisition; the potential effectiveness of our risk management strategies; new accounting standards, the timing for the adoption thereof by Cenovus, and anticipated impact on the Consolidated Financial Statements; expected impacts of the Acquisition; the availability and repayment of our credit facilities; potential asset sales and anticipated use of sales proceeds; expected impacts of the contingent payment related to the Acquisition; future use and development of technology; our ability to access and implement all technology necessary to efficiently and effectively operate our assets and achieve expected future cost reductions; and projected growth and projected shareholder return. Readers are cautioned not to place undue reliance on forward-looking information as our actual results may differ materially from those expressed or implied.

Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to Cenovus and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include: forecast oil and natural gas, natural gas liquids, condensate and refined products prices and other assumptions inherent in Cenovus's 2018 guidance, available at cenovus.com; our projected capital investment levels, the flexibility of our capital spending plans and the associated source of funding; the achievement of further cost reductions and sustainability thereof; expected condensate prices; estimates of quantities of oil, bitumen, natural gas and liquids from properties and other sources not currently classified as proved; future use and development of technology; our ability to obtain necessary regulatory and partner approvals; the successful and timely implementation of capital projects or stages thereof; our ability to generate sufficient cash flow to meet our current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; achievement of expected impacts of the Acquisition; successful integration of the Deep Basin Assets; our ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; our ability to access sufficient capital to pursue our development plans; our ability to complete asset sales, including with desired transaction metrics and the timelines we expect; forecast bitumen, crude oil, natural gas liquids, condensate and refined products prices, forecast inflation and other assumptions inherent in our current guidance set out below; expected impacts of the contingent payment to ConocoPhillips; alignment of realized Western Canadian Select ("WCS") prices and WCS prices used to calculate the contingent payment to ConocoPhillips; our projected capital investment levels, the flexibility of capital spending plans and the associated sources of funding; sustainability of achieved cost reductions, achievement of further cost reductions and sustainability thereof; our ability to access and implement all technology necessary to achieve expected future results; our ability to implement capital projects or stages thereof in a successful and timely manner; and other risks and uncertainties described from time to time in the filings we make with securities regulatory authorities.

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

The risk factors and uncertainties that could cause our actual results to differ materially, include: possible failure by us to realize the anticipated benefits of and synergies from the Acquisition; possible failure to access or implement some or all of the technology necessary to efficiently and effectively operate our assets and achieve expected future results; volatility of and other assumptions regarding commodity prices; the effectiveness of our risk management program, including the impact of derivative financial instruments, the success of our hedging strategies and the sufficiency of our liquidity position; the accuracy of cost estimates; commodity prices, currency and interest rates; possible lack of alignment of realized WCS prices and WCS prices used to calculate the contingent payment to ConocoPhillips; product supply and demand; market competition, including from alternative energy sources; risks inherent in our marketing operations, including credit risks; exposure to counterparties and partners, including ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent in the operation of our crude-by-rail terminal, including health, safety and environmental risks; maintaining desirable ratios of Net Debt to Adjusted EBITDA as well as Net Debt to Capitalization; our ability to access various sources of debt and equity capital, generally, and on terms acceptable to us; our ability to finance growth and sustaining capital expenditures; changes in credit ratings applicable to us or any of our securities; changes to our dividend plans or strategy, including the dividend reinvestment plan; accuracy of our reserves, future production and future net revenue estimates; our ability to replace and expand oil and gas reserves; our ability to maintain our relationship with our partners and to successfully manage and operate our integrated business; reliability of our assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and manufacturing processes; the occurrence of unexpected events such as fires, severe weather conditions, explosions, blow-outs, equipment failures, transportation incidents and other accidents or similar events; refining and marketing margins; inflationary pressures on operating costs, including labour, materials, natural gas and other energy sources used in oil sands processes; potential failure of products to achieve or maintain acceptance in the market; risks associated with fossil fuel industry reputation; unexpected cost increases or technical difficulties in constructing or modifying manufacturing or refining facilities; unexpected difficulties in producing, transporting or refining of bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and its application to our business; risks associated with climate change; the timing and the costs of well and pipeline construction; our ability to secure adequate and cost-effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system; availability of, and our ability to attract and retain, critical talent; possible failure to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; changes in labour relationships; changes in the regulatory framework in any of the locations in which we operate, including changes to the regulatory approval process and land-use designations, royalty, tax, environmental, greenhouse gas, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on our business, our financial results and our Consolidated Financial Statements; changes in general economic, market and business conditions; the political and economic conditions in the countries in which we operate or supply; the occurrence of unexpected events such as war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits and regulatory actions against us.

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

Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward looking information. For a full discussion of our material risk factors, see “Risk Management and Risk Factors” in this MD&A for the period ended December 31, 2017, available on SEDAR at sedar.com, on EDGAR at sec.gov and on our website at cenovus.com.

ABBREVIATIONS

The following abbreviations have been used in this document:

Crude Oil	
bbl	Barrel
Mbbls/d	thousand barrels per day
MMbbls	million barrels
BOE	barrel of oil equivalent
MMBOE	million barrel of oil equivalent
WTI	West Texas Intermediate
WCS	Western Canadian Select
CDB	Christina Dilbit Blend
MSW	Mixed Sweet Blend

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
MMBtu	million British thermal units
GJ	gigajoule
AECO	Alberta Energy Company
NYMEX	New York Mercantile Exchange

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

	Per Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
Year Ended December 31, 2017 ($ millions)	Oil Sands [1]	Deep Basin [1]	Continuing Operations	Condensate	Inventory	Other	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

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

	Per Consolidated Financial Statements				Adjustments			Basis of Netback Calculation
Year Ended December 31, 2015 ($ millions)	Oil Sands [1]	Deep Basin [1]	Conventional [2]	Continuing Operations	Condensate	Inventory	Other	Continuing Operations
Gross Sales	3,030	-	61	3,091	(1,441)	-	(8)	1,642
Royalties	29	-	1	30	-	-	-	30
Transportation and Blending	1,815	-	1	1,816	(1,441)	(38)	-	337
Operating	531	-	3	534	-	-	(5)	529
Production and Mineral Taxes	-	-	1	1	-	-	-	1
Netback	655	-	55	710	-	38	(3)	745
(Gain) Loss on Risk Management	(404)	-	-	(404)	-	-	-	(404)
Operating Margin	1,059	-	55	1,114	-	38	(3)	1,149

	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
Three Months Ended December 31, 2017 ($ millions)	Oil Sands [3]	Deep Basin [3]	Continuing Operations	Condensate	Inventory	Other	Continuing Operations
Gross Sales	2,424	231	2,655	(990)	-	(15)	1,650
Royalties	113	20	133	-	-	-	133
Transportation and Blending	1,193	24	1,217	(990)	(1)	2	228
Operating	271	94	365	-	-	(15)	350
Production and Mineral Taxes	-	1	1	-	-	-	1
Netback	847	92	939	-	1	(2)	938
(Gain) Loss on Risk Management	235	-	235	-	-	-	235
Operating Margin	612	92	704	-	1	(2)	703

Three Months Ended September 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Oil Sands [3]	Deep Basin [3]	Continuing Operations	Condensate	Inventory	Other	Continuing Operations
Gross Sales	2,210	200	2,410	(863)	-	(19)	1,528
Royalties	54	13	67	-	-	-	67
Transportation and Blending	1,066	22	1,088	(863)	1	(1)	225
Operating [4]	259	101	360	-	-	(9)	351
Production and Mineral Taxes	-	-	-	-	-	-	-
Netback	831	64	895	-	(1)	(9)	885
(Gain) Loss on Risk Management	9	-	9	-	-	-	9
Operating Margin	822	64	886	-	(1)	(9)	876

Three Months Ended June 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Oil Sands [3]	Deep Basin [3]	Continuing Operations	Condensate	Inventory	Other	Continuing Operations
Gross Sales	1,666	124	1,790	(719)	-	(6)	1,065
Royalties	36	8	44	-	-	-	44
Transportation and Blending	879	10	889	(719)	-	(2)	168
Operating [5]	264	55	319	-	-	(52)	267
Production and Mineral Taxes	-	-	-	-	-	-	-
Netback	487	51	538	-	-	48	586
(Gain) Loss on Risk Management	(14)	-	(14)	-	-	-	(14)
Operating Margin	501	51	552	-	-	48	600

Three Months Ended March 31, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Oil Sands [3]	Deep Basin [3]	Continuing Operations	Condensate	Inventory	Other	Continuing Operations
Gross Sales	1,062	-	1,062	(478)	-	(5)	579
Royalties	27	-	27	-	-	-	27
Transportation and Blending	566	-	566	(478)	-	-	88
Operating	140	-	140	-	-	(1)	139
Production and Mineral Taxes	-	-	-	-	-	-	-
Netback	329	-	329	-	-	(4)	325
(Gain) Loss on Risk Management	77	-	77	-	-	-	77
Operating Margin	252	-	252	-	-	(4)	248

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Includes the results of operation for certain Conventional segment royalty interest assets disposed of in 2015.
(3) Found in Note 1 of the Interim Consolidated Financial Statements.
(4) As a result of measurement period adjustments related to the Acquisition, operating costs for the Oil Sands segment were increased by $2 million in the third quarter of 2017.
(5) As a result of measurement period adjustments related to the Acquisition, operating costs for the Oil Sands and Deep Basin segments were increased by $43 million and $4 million, respectively, in the second quarter of 2017.

Oil Sands

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

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

Year Ended December 31, 2015 ($ millions)	Basis of Netback Calculation				Adjustments			Per Consolidated Financial Statements [1]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	792	767	1,559	22	1,441	-	8	3,030
Royalties	11	18	29	-	-	-	-	29
Transportation and Blending	208	127	335	1	1,441	38	-	1,815
Operating	295	216	511	15	-	-	5	531
Netback	278	406	684	6	-	(38)	3	655
(Gain) Loss on Risk Management	(202)	(198)	(400)	(4)	-	-	-	(404)
Operating Margin	480	604	1,084	10	-	(38)	3	1,059

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

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements [2]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	603	737	1,340	1	863	-	6	2,210
Royalties	43	11	54	-	-	-	-	54
Transportation and Blending	126	79	205	-	863	(1)	(1)	1,066
Operating [3]	138	116	254	1	-	-	4	259
Netback	296	531	827	-	-	1	3	831
(Gain) Loss on Risk Management	2	7	9	-	-	-	-	9
Operating Margin	294	524	818	-	-	1	3	822

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements [2]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	429	514	943	4	719	-	-	1,666
Royalties	24	12	36	-	-	-	-	36
Transportation and Blending	100	58	158	-	719	-	2	879
Operating [3]	119	99	218	2	-	-	44	264
Netback	186	345	531	2	-	-	(46)	487
(Gain) Loss on Risk Management	(9)	(5)	(14)	-	-	-	-	(14)
Operating Margin	195	350	545	2	-	-	(46)	501

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation				Adjustments			Per Interim Consolidated Financial Statements [2]
	Foster Creek	Christina Lake	Total Crude Oil	Natural Gas	Condensate	Inventory	Other	Total Oil Sands
Gross Sales	287	290	577	2	478	-	5	1,062
Royalties	20	7	27	-	-	-	-	27
Transportation and Blending	55	33	88	-	478	-	-	566
Operating	71	65	136	3	-	-	1	140
Netback	141	185	326	(1)	-	-	4	329
(Gain) Loss on Risk Management	40	37	77	-	-	-	-	77
Operating Margin	101	148	249	(1)	-	-	4	252

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Found in Note 1 of the Interim Consolidated Financial Statements.
(3) As a result of measurement period adjustments related to the Acquisition, operating costs were increased by $43 million and $2 million in the second and third quarters of 2017, respectively.

Deep Basin

Year Ended December 31, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Consolidated Financial Statements [1] 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

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

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements [2] Total Deep Basin
Gross Sales	187	13	200
Royalties	13	-	13
Transportation and Blending	20	2	22
Operating	96	5	101
Production and Mineral Taxes	-	-	-
Netback	58	6	64
(Gain) Loss on Risk Management	-	-	-
Operating Margin	58	6	64

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation Total	Adjustments Other	Per Interim Consolidated Financial Statements [2] Total Deep Basin
Gross Sales	118	6	124
Royalties	8	-	8
Transportation and Blending	10	-	10
Operating [3]	47	8	55
Production and Mineral Taxes	-	-	-
Netback	53	(2)	51
(Gain) Loss on Risk Management	-	-	-
Operating Margin	53	(2)	51

(1) Found in Note 1 of the Consolidated Financial Statements.
(2) Found in Note 1 of the Interim Consolidated Financial Statements.
(3) As a result of measurement period adjustments related to the Acquisition, operating costs were increased by $4 million in the second quarter of 2017.

Conventional (Discontinued Operations)

Year Ended December 31, 2017 ($ millions)	Basis of Netback Calculation Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Adjustments Condensate	Inventory	Other	Per Consolidated Financial Statements [1] Total Conventional
Gross Sales	383	504	17	904	300	1,204	95	-	10	1,309
Royalties	51	107	2	160	14	174	-	-	-	174
Transportation and Blending	35	25	-	60	12	72	95	-	-	167
Operating	117	153	-	270	152	422	-	-	4	426
Production and Mineral Taxes	-	17	-	17	1	18	-	-	-	18
Netback	180	202	15	397	121	518	-	-	6	524
(Gain) Loss on Risk Management	14	23	-	37	(4)	33	-	-	-	33
Operating Margin	166	179	15	360	125	485	-	-	6	491

Year Ended December 31, 2016 ($ millions)	Basis of Netback Calculation						Adjustments			Per Consolidated Financial Statements[1]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	380	442	11	833	319	1,152	103	-	12	1,267
Royalties	35	88	2	125	14	139	-	-	-	139
Transportation and Blending	49	25	-	74	16	90	103	(7)	-	186
Operating	142	149	-	291	154	445	-	-	(1)	444
Production and Mineral Taxes	-	12	-	12	-	12	-	-	-	12
Netback	154	168	9	331	135	466	-	7	13	486
(Gain) Loss on Risk Management	(34)	(30)	-	(64)	-	(64)	-	-	6	(58)
Operating Margin	188	198	9	395	135	530	-	7	7	544

Year Ended December 31, 2015 ($ millions)	Basis of Netback Calculation						Adjustments			Per Consolidated Financial Statements[1]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	507	528	13	1,048	435	1,483	142	-	23	1,648
Royalties	39	62	1	102	11	113	-	-	-	113
Transportation and Blending	44	31	-	75	17	92	142	(5)	-	229
Operating	206	180	-	386	177	563	-	-	(5)	558
Production and Mineral Taxes	-	15	-	15	2	17	-	-	-	17
Netback	218	240	12	470	228	698	-	5	28	731
(Gain) Loss on Risk Management	(88)	(76)	-	(164)	(55)	(219)	-	-	10	(209)
Operating Margin	306	316	12	634	283	917	-	5	18	940

Three Months Ended December 31, 2017 ($ millions)	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[2]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	40	107	4	151	53	204	8	-	6	218
Royalties	2	24	-	26	2	28	-	-	1	29
Transportation and Blending	3	5	-	8	2	10	8	-	-	18
Operating	14	32	-	46	35	81	-	-	2	83
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
Netback	21	42	4	67	14	81	-	-	3	84
(Gain) Loss on Risk Management	4	13	-	17	(3)	14	-	-	-	14
Operating Margin	17	29	4	50	17	67	-	-	3	70

Three Months Ended September 30, 2017 ($ millions)	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[2]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	111	131	4	246	62	308	22	-	1	331
Royalties	17	26	1	44	3	47	-	-	(2)	45
Transportation and Blending	13	7	-	20	3	23	22	-	(1)	44
Operating	35	44	-	79	39	118	-	-	-	118
Production and Mineral Taxes	-	4	-	4	-	4	-	-	-	4
Netback	46	50	3	99	17	116	-	-	4	120
(Gain) Loss on Risk Management	1	3	-	4	(1)	3	-	-	-	3
Operating Margin	45	47	3	95	18	113	-	-	4	117

Three Months Ended June 30, 2017 ($ millions)	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[2]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	119	138	4	261	90	351	32	-	3	386
Royalties	16	28	-	44	5	49	-	-	1	50
Transportation and Blending	11	7	-	18	3	21	32	-	1	54
Operating	37	39	-	76	37	113	-	-	2	115
Production and Mineral Taxes	-	5	-	5	-	5	-	-	-	5
Netback	55	59	4	118	45	163	-	-	(1)	162
(Gain) Loss on Risk Management	2	1	-	3	-	3	-	-	-	3
Operating Margin	53	58	4	115	45	160	-	-	(1)	159

Three Months Ended March 31, 2017 ($ millions)	Basis of Netback Calculation						Adjustments			Per Interim Consolidated Financial Statements[(2)]
	Heavy Oil	Light & Medium	NGLs	Conventional Liquids	Natural Gas	Conventional	Condensate	Inventory	Other	Total Conventional
Gross Sales	113	128	5	246	95	341	33	-	-	374
Royalties	16	29	1	46	4	50	-	-	-	50
Transportation and Blending	8	6	-	14	4	18	33	-	-	51
Operating	31	38	-	69	41	110	-	-	-	110
Production and Mineral Taxes	-	4	-	4	1	5	-	-	-	5
Netback	58	51	4	113	45	158	-	-	-	158
(Gain) Loss on Risk Management	7	6	-	13	-	13	-	-	-	13
Operating Margin	51	45	4	100	45	145	-	-	-	145

(1) Found in Note 11 of the Consolidated Financial Statements and includes operating results associated with our royalty interest assets sold in 2015 consisting of gross sales, royalties, transportation and blending expenses, operating expenses, and production and mineral taxes in the amount of $61 million, $1 million, $1 million, $3 million and $1 million, respectively.

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

Total Production

Upstream Financial Results

Year Ended December 31, 2017 ($ millions)	Per Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [(1)]	Conventional [(2)]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	7,917	1,309	9,226	(3,145)	-	(55)	6,026
Royalties	271	174	445	-	-	-	445
Transportation and Blending	3,760	167	3,927	(3,145)	-	(2)	780
Operating	1,184	426	1,610	-	-	(81)	1,529
Production and Mineral Taxes	1	18	19	-	-	-	19
Netback	2,701	524	3,225	-	-	28	3,253
(Gain) Loss on Risk Management	307	33	340	-	-	-	340
Operating Margin	2,394	491	2,885	-	-	28	2,913

Year Ended December 31, 2016 ($ millions)	Per Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [(1)]	Conventional [(2)]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	2,929	1,267	4,196	(1,505)	-	(14)	2,677
Royalties	9	139	148	-	-	-	148
Transportation and Blending	1,721	186	1,907	(1,505)	51	-	453
Operating	501	444	945	-	-	(3)	942
Production and Mineral Taxes	-	12	12	-	-	-	12
Netback	698	486	1,184	-	(51)	(11)	1,122
(Gain) Loss on Risk Management	(179)	(58)	(237)	-	-	(6)	(243)
Operating Margin	877	544	1,421	-	(51)	(5)	1,365

Year Ended December 31, 2015 ($ millions)	Per Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [(1)]	Conventional [(2)]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	3,091	1,648	4,739	(1,583)	-	(31)	3,125
Royalties	30	113	143	-	-	-	143
Transportation and Blending	1,816	229	2,045	(1,583)	(33)	-	429
Operating	534	558	1,092	-	-	-	1,092
Production and Mineral Taxes	1	17	18	-	-	-	18
Netback	710	731	1,441	-	33	(31)	1,443
(Gain) Loss on Risk Management	(404)	(209)	(613)	-	-	(10)	(623)
Operating Margin	1,114	940	2,054	-	33	(21)	2,066

Three Months Ended December 31, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [(1)]	Conventional [(3)]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	2,655	218	2,873	(998)	-	(21)	1,854
Royalties	133	29	162	-	-	(1)	161
Transportation and Blending	1,217	18	1,235	(998)	(1)	1	237
Operating	365	83	448	-	-	(17)	431
Production and Mineral Taxes	1	4	5	-	-	-	5
Netback	939	84	1,023	-	1	(4)	1,020
(Gain) Loss on Risk Management	235	14	249	-	-	-	249
Operating Margin	704	70	774	-	1	(4)	771

Three Months Ended September 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [1]	Conventional [3]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	2,410	331	2,741	(885)	-	(20)	1,836
Royalties	67	45	112	-	-	2	114
Transportation and Blending	1,088	44	1,132	(885)	1	-	248
Operating	360	118	478	-	-	(9)	469
Production and Mineral Taxes	-	4	4	-	-	-	4
Netback	895	120	1,015	-	(1)	(13)	1,001
(Gain) Loss on Risk Management	9	3	12	-	-	-	12
Operating Margin	886	117	1,003	-	(1)	(13)	989

Three Months Ended June 30, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [1]	Conventional [3]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	1,790	386	2,176	(751)	-	(9)	1,416
Royalties	44	50	94	-	-	(1)	93
Transportation and Blending	889	54	943	(751)	-	(3)	189
Operating	319	115	434	-	-	(54)	380
Production and Mineral Taxes	-	5	5	-	-	-	5
Netback	538	162	700	-	-	49	749
(Gain) Loss on Risk Management	(14)	3	(11)	-	-	-	(11)
Operating Margin	552	159	711	-	-	49	760

Three Months Ended March 31, 2017 ($ millions)	Per Interim Consolidated Financial Statements			Adjustments			Basis of Netback Calculation
	Continuing Operations [1]	Conventional [3]	Total Operations	Condensate	Inventory	Other	Total Operations
Gross Sales	1,062	374	1,436	(511)	-	(5)	920
Royalties	27	50	77	-	-	-	77
Transportation and Blending	566	51	617	(511)	-	-	106
Operating	140	110	250	-	-	(1)	249
Production and Mineral Taxes	-	5	5	-	-	-	5
Netback	329	158	487	-	-	(4)	483
(Gain) Loss on Risk Management	77	13	90	-	-	-	90
Operating Margin	252	145	397	-	-	(4)	393

(1) Continuing operations consist of the Oil Sands and Deep Basin segments.
(2) Classified as a discontinued operation, which can be found in Note 11 of the Consolidated Financial Statements.
(3) Classified as a discontinued operation, which can be found in Note 9 of the Interim Consolidated Financial Statements.

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

Sales Volumes

(barrels per day, unless otherwise stated)	Twelve Months Ended December 31		
	2017	2016	2015
Oil Sands			
Foster Creek	**121,806**	69,647	64,467
Christina Lake	**161,514**	79,481	73,872
Total Oil Sands Crude Oil	**283,320**	149,128	138,339
Natural Gas (MMcf per day)	**10**	17	19
Deep Basin			
Total Liquids	**20,850**	-	-
Natural Gas (MMcf per day)	**316**	-	-
Conventional Sales (BOE per day)	**-**	-	4,163
Sales From Continuing Operations (BOE per day)	**358,476**	151,962	145,669
Conventional (Discontinued Operations)			
Heavy Oil	**21,669**	28,958	34,965
Light and Medium Oil	**24,571**	25,965	28,706
Natural Gas Liquids ("NGLs")	**1,073**	1,065	1,149
Total Conventional Liquids	**47,313**	55,988	64,820
Natural Gas (MMcf per day)	**333**	377	412
Sales From Discontinued Operations (BOE per day)	**102,792**	118,821	133,537
Total Liquids Sales	**351,483**	205,116	205,706
Total Sales (BOE per day)	**461,268**	270,783	279,206

(barrels per day, unless otherwise stated)	Three Months Ended			
	December 31, 2017	September 30, 2017	June 30, 2017	March 31, 2017
Oil Sands				
Foster Creek	**143,586**	157,850	106,115	78,562
Christina Lake	**193,734**	206,338	154,431	89,919
Total Oil Sands Crude Oil	**337,320**	364,188	260,546	168,481
Natural Gas (MMcf per day)	**7**	6	12	15
Deep Basin				
Total Liquids	**33,147**	32,864	16,894	-
Natural Gas (MMcf per day)	**509**	495	253	-
Sales From Continuing Operations (BOE per day)	**456,455**	480,512	321,526	170,981
Conventional (Discontinued Operations)				
Heavy Oil	**7,485**	25,047	28,089	26,222
Light and Medium Oil	**18,915**	27,494	26,835	25,074
Natural Gas Liquids ("NGLs")	**913**	1,201	1,132	1,047
Total Conventional Liquids	**27,313**	53,742	56,056	52,343
Natural Gas (MMcf per day)	**279**	350	355	348
Sales From Discontinued Operations (BOE per day)	**73,775**	112,079	115,235	110,343
Total Liquids Sales	**397,780**	450,794	333,496	220,824
Total Sales (BOE per day)	**530,230**	592,591	436,761	281,324