Cenovus Energy Inc.

Consolidated Financial Statements

For the Year Ended December 31, 2017

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS

For the year ended December 31, 2017

TABLE OF CONTENTS

REPORT OF MANAGEMENT 3
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM 4
CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) 6
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) 7
CONSOLIDATED BALANCE SHEETS 8
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY 9
CONSOLIDATED STATEMENTS OF CASH FLOWS 10
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS 11

1. Description Of Business And Segmented Disclosures 11
2. Basis Of Preparation And Statement Of Compliance 14
3. Summary Of Significant Accounting Policies 14
4. Critical Accounting Judgments And Key Sources Of Estimation Uncertainty 22
5. Acquisition 24
6. Finance Costs 26
7. Foreign Exchange (Gain) Loss, Net 27
8. Divestitures 27
9. Other (Income) Loss, Net 27
10. Impairment Charges And Reversals 27
11. Assets Held For Sale And Discontinued Operations 30
12. Income Taxes 32
13. Per Share Amounts 34
14. Cash And Cash Equivalents 34
15. Accounts Receivable And Accrued Revenues 34
16. Inventories 35
17. Exploration And Evaluation Assets 35
18. Property, Plant And Equipment, Net 36
19. Other Assets 37
20. Goodwill 37
21. Accounts Payable And Accrued Liabilities 37
22. Contingent Payment 37
23. Long-Term Debt 38
24. Decommissioning Liabilities 39
25. Other Liabilities 40
26. Pensions And Other Post-Employment Benefits 40
27. Share Capital 43
28. Accumulated Other Comprehensive Income (Loss) 44
29. Stock-Based Compensation Plans 44
30. Employee Salaries And Benefit Expenses 47
31. Related Party Transactions 47
32. Capital Structure 47
33. Financial Instruments 49
34. Risk Management 51
35. Supplementary Cash Flow Information 53
36. Commitments And Contingencies 54

REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of four independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States *Sarbanes – Oxley Act of 2002* and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and approve interim Consolidated Financial Statements and Management's Discussion and Analysis prior to their public release as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

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.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2017. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") 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 internal control over financial reporting was 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. The Deep Basin total assets and total revenues excluded from Management's assessment of internal control over financial reporting represents 16 percent and three percent, respectively, of the related Consolidated Financial Statement amounts as at and for the year ended December 31, 2017.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, was appointed to audit and provide independent opinions on both the Consolidated Financial Statements and internal control over financial reporting as at December 31, 2017, as stated in their Report of Independent Registered Public Accounting Firm dated February 14, 2018. PricewaterhouseCoopers LLP has provided such opinions.

/s/ Alexander J. Pourbaix

Alexander J. Pourbaix
President &
Chief Executive Officer
Cenovus Energy Inc.

/s/ Ivor M. Ruste

Ivor M. Ruste
Executive Vice-President &
Chief Financial Officer
Cenovus Energy Inc.

February 14, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Cenovus Energy Inc.

Opinions on the Consolidated Financial Statements and Internal Control Over Financial Reporting

We have audited the accompanying Consolidated Balance Sheets of Cenovus Energy Inc. and its subsidiaries, (together the "Company") as of December 31, 2017 and December 31, 2016, and the related Consolidated Statements of Earnings (Loss), Comprehensive Income (Loss), Shareholders' Equity, and Cash Flows for each of the years in the three-year period ended December 31, 2017, including the related notes (collectively referred to as the "Consolidated Financial Statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the Consolidated Financial Statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017 and December 31, 2016 and its consolidated financial performance and its consolidated cash flows for each of the years in the three-year period ended December 31, 2017 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by COSO.

Basis for Opinions

The Company's Management is responsible for these Consolidated Financial Statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's Consolidated Financial Statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the Consolidated Financial Statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the Consolidated Financial Statements included performing procedures to assess the risks of material misstatement of the Consolidated Financial Statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the Consolidated Financial Statements. Our audits also included evaluating the accounting principles used and significant estimates made by Management, as well as evaluating the overall presentation of the Consolidated Financial Statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Management's Assessment of Internal Control over Financial Reporting, Management has excluded the Deep Basin assets from its assessment of internal control over financial reporting as of December 31, 2017 because it was acquired by the Company through a business combination in 2017. We have also excluded the Deep Basin assets from our audit of internal control over financial reporting. The Deep Basin total assets and total revenues excluded from Management's assessment and our audit of internal control over financial reporting represent 16 percent and three percent, respectively, of the related Consolidated Financial Statement amounts as at and for the year ended December 31, 2017.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. 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.

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Chartered Professional Accountants
Calgary, Alberta, Canada

February 14, 2018

We have served as the Company's auditor since 2008.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	2017	2016	2015
			(Restated)[1]	(Restated)[1]
Revenues	1			
Gross Sales		**17,314**	11,015	11,559
Less: Royalties		**271**	9	30
		17,043	11,006	11,529
Expenses	1			
Purchased Product		**8,033**	6,978	7,374
Transportation and Blending		**3,748**	1,715	1,814
Operating		**1,949**	1,239	1,281
Production and Mineral Taxes		**1**	-	1
(Gain) Loss on Risk Management	33	**896**	401	(252)
Depreciation, Depletion and Amortization	18	**1,838**	931	993
Exploration Expense	17	**888**	2	67
General and Administrative		**308**	326	335
Finance Costs	6	**645**	390	381
Interest Income		**(62)**	(52)	(28)
Foreign Exchange (Gain) Loss, Net	7	**(812)**	(198)	1,036
Revaluation (Gain)	5	**(2,555)**	-	-
Transaction Costs	5	**56**	-	-
Re-measurement of Contingent Payment	5,22	**(138)**	-	-
Research Costs		**36**	36	27
(Gain) Loss on Divestiture of Assets	8	**1**	6	(2,392)
Other (Income) Loss, Net	9	**(5)**	34	2
Earnings (Loss) From Continuing Operations Before Income Tax		**2,216**	(802)	890
Income Tax Expense (Recovery)	12	**(52)**	(343)	(24)
Net Earnings (Loss) From Continuing Operations		**2,268**	(459)	914
Net Earnings (Loss) From Discontinued Operations	11	**1,098**	(86)	(296)
Net Earnings (Loss)		**3,366**	(545)	618
Basic and Diluted Earnings (Loss) Per Share ($)	13			
Continuing Operations		**2.06**	(0.55)	1.11
Discontinued Operations		**0.99**	(0.10)	(0.36)
Net Earnings (Loss) Per Share		**3.05**	(0.65)	0.75

(1) The comparative periods have been restated to reflect discontinued operations as discussed in Notes 1 and 11.

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions)

	Notes	2017	2016	2015
Net Earnings (Loss)		**3,366**	(545)	618
Other Comprehensive Income (Loss), Net of Tax	28			
Items That Will Not be Reclassified to Profit or Loss:				
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**9**	(3)	20
Items That May be Reclassified to Profit or Loss:				
Available for Sale Financial Assets – Change in Fair Value		**(1)**	(2)	6
Available for Sale Financial Assets – Reclassified to Profit or Loss		**-**	1	-
Foreign Currency Translation Adjustment		**(275)**	(106)	587
Total Other Comprehensive Income (Loss), Net of Tax		**(267)**	(110)	613
Comprehensive Income (Loss)		**3,099**	(655)	1,231

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	**2017**	2016
Assets			
Current Assets			
Cash and Cash Equivalents	14	**610**	3,720
Accounts Receivable and Accrued Revenues	15	**1,830**	1,838
Income Tax Receivable		**68**	6
Inventories	16	**1,389**	1,237
Risk Management	33,34	**63**	21
Assets Held for Sale	11	**1,048**	-
Total Current Assets		**5,008**	6,822
Exploration and Evaluation Assets	1,17	**3,673**	1,585
Property, Plant and Equipment, Net	1,18	**29,596**	16,426
Income Tax Receivable		**311**	124
Risk Management	33,34	**2**	3
Other Assets	19	**71**	56
Goodwill	1,20	**2,272**	242
Total Assets		**40,933**	25,258
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	21	**2,635**	2,266
Contingent Payment	22	**38**	-
Income Tax Payable		**129**	112
Risk Management	33,34	**1,031**	293
Liabilities Related to Assets Held for Sale	11	**603**	-
Total Current Liabilities		**4,436**	2,671
Long-Term Debt	23	**9,513**	6,332
Contingent Payment	22	**168**	-
Risk Management	33,34	**20**	22
Decommissioning Liabilities	24	**1,029**	1,847
Other Liabilities	25	**173**	211
Deferred Income Taxes	12	**5,613**	2,585
Total Liabilities		**20,952**	13,668
Shareholders' Equity		**19,981**	11,590
Total Liabilities and Shareholders' Equity		**40,933**	25,258
Commitments and Contingencies	36		

See accompanying Notes to Consolidated Financial Statements.

Approved by the Board of Directors

/s/ Patrick D. Daniel

Patrick D. Daniel
Director
Cenovus Energy Inc.

/s/ Colin Taylor

Colin Taylor
Director
Cenovus Energy Inc.

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	**Total**
	(Note 27)	(Note 27)		(Note 28)	
As at December 31, 2014	3,889	4,291	1,599	407	10,186
Net Earnings	-	-	618	-	618
Other Comprehensive Income	-	-	-	613	613
Total Comprehensive Income	-	-	618	613	1,231
Common Shares Issued for Cash	1,463	-	-	-	1,463
Common Shares Issued Pursuant to Dividend Reinvestment Plan	182	-	-	-	182
Stock-Based Compensation Expense	-	39	-	-	39
Dividends on Common Shares	-	-	(710)	-	(710)
As at December 31, 2015	5,534	4,330	1,507	1,020	12,391
Net Earnings (Loss)	-	-	(545)	-	(545)
Other Comprehensive Income (Loss)	-	-	-	(110)	(110)
Total Comprehensive Income (Loss)	-	-	(545)	(110)	(655)
Stock-Based Compensation Expense	-	20	-	-	20
Dividends on Common Shares	-	-	(166)	-	(166)
As at December 31, 2016	**5,534**	**4,350**	**796**	**910**	**11,590**
Net Earnings (Loss)	**-**	**-**	**3,366**	**-**	**3,366**
Other Comprehensive Income (Loss)	**-**	**-**	**-**	**(267)**	**(267)**
Total Comprehensive Income (Loss)	**-**	**-**	**3,366**	**(267)**	**3,099**
Common Shares Issued	**5,506**	**-**	**-**	**-**	**5,506**
Stock-Based Compensation Expense	**-**	**11**	**-**	**-**	**11**
Dividends on Common Shares	**-**	**-**	**(225)**	**-**	**(225)**
As at December 31, 2017	**11,040**	**4,361**	**3,937**	**643**	**19,981**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	**2017**	2016	2015
Operating Activities				
Net Earnings (Loss)		**3,366**	(545)	618
Depreciation, Depletion and Amortization	18	**2,030**	1,498	2,114
Exploration Expense	17	**890**	2	138
Deferred Income Taxes	12	**583**	(209)	(655)
Unrealized (Gain) Loss on Risk Management	33	**729**	554	195
Unrealized Foreign Exchange (Gain) Loss	7	**(857)**	(189)	1,097
Revaluation (Gain)	5	**(2,555)**	-	-
Re-measurement of Contingent Payment	22	**(138)**	-	-
(Gain) Loss on Discontinuance	11	**(1,285)**	-	-
(Gain) Loss on Divestiture of Assets	8	**1**	6	(2,392)
Current Tax on Divestiture of Assets	8	**-**	-	391
Unwinding of Discount on Decommissioning Liabilities	24	**128**	130	126
Onerous Contract Provisions, Net of Cash Paid		**(8)**	53	-
Other Asset Impairments	9	**-**	30	-
Other		**30**	93	59
Net Change in Other Assets and Liabilities		**(107)**	(91)	(107)
Net Change in Non-Cash Working Capital		**252**	(471)	(110)
Cash From Operating Activities		**3,059**	861	1,474
Investing Activities				
Acquisition, Net of Cash Acquired	5	**(14,565)**	-	(84)
Capital Expenditures – Exploration and Evaluation Assets	17	**(147)**	(67)	(138)
Capital Expenditures – Property, Plant and Equipment	18	**(1,523)**	(967)	(1,576)
Proceeds From Divestiture of Assets	8	**3,210**	8	3,344
Current Tax on Divestiture of Assets	8	**-**	-	(391)
Net Change in Investments and Other		**-**	(1)	3
Net Change in Non-Cash Working Capital		**159**	(52)	(270)
Cash From (Used in) Investing Activities		**(12,866)**	(1,079)	888
Net Cash Provided (Used) Before Financing Activities		**(9,807)**	(218)	2,362
Financing Activities	35			
Net Issuance (Repayment) of Short-Term Borrowings	23	**-**	-	(25)
Issuance of Long-Term Debt	23	**3,842**	-	-
Net Issuance (Repayment) of Revolving Long-Term Debt	23	**32**	-	-
Net Issuance of Debt Under Asset Sale Bridge Facility	23	**3,569**	-	-
Repayment of Debt Under Asset Sale Bridge Facility	23	**(3,600)**	-	-
Common Shares Issued, Net of Issuance Costs	27	**2,899**	-	1,449
Dividends Paid on Common Shares	13	**(225)**	(166)	(528)
Other		**(2)**	(2)	(2)
Cash From (Used in) 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
Cash and Cash Equivalents, Beginning of Year		**3,720**	4,105	883
Cash and Cash Equivalents, End of Year		**610**	3,720	4,105
Supplementary Cash Flow Information	35			

See accompanying Notes to Consolidated Financial Statements.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. and its subsidiaries, (together "Cenovus" or the "Company") are in the business of developing, producing and marketing crude oil, natural gas liquids ("NGLs") and natural gas in Canada with marketing activities and refining operations in the United States ("U.S.").

Cenovus is incorporated under the Canada Business Corporations Act and its shares are listed on the Toronto ("TSX") and New York ("NYSE") stock exchanges. The executive and registered office is located at 2600, 500 Centre Street S.E., Calgary, Alberta, Canada, T2G 1A6. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

On May 17, 2017, Cenovus acquired from ConocoPhillips Company and certain of its subsidiaries (collectively, "ConocoPhillips") a 50 percent interest in FCCL Partnership ("FCCL") and the majority of ConocoPhillips' western Canadian conventional crude oil and natural gas assets (the "Deep Basin Assets"). This acquisition (the "Acquisition") increased Cenovus's interest in FCCL to 100 percent and expanded Cenovus's operating areas to include more than three million net acres of land, exploration and production assets and related infrastructure and agreements in Alberta and British Columbia. The Acquisition had an effective date of January 1, 2017 (see Note 5).

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision makers. The Company evaluates the financial performance of its operating segments primarily based on operating margin. The Company's reportable segments are:

- **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. The Company's interest in certain of its operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, increased from 50 percent to 100 percent on May 17, 2017.
- **Deep Basin**, which includes approximately three million net acres of land primarily in the Elmworth-Wapiti, Kaybob-Edson, and Clearwater operating areas, rich in natural gas and NGLs. The assets reside in Alberta and British Columbia and include interests in numerous natural gas processing facilities. 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. The marketing of crude oil and natural gas sourced from Canada, including physical product sales that settle in the U.S., is considered to be undertaken by a Canadian business. U.S. sourced crude oil and natural gas purchases and sales are attributed to the U.S.
- **Corporate and Eliminations**, which primarily includes unrealized gains and losses recorded on derivative financial instruments, gains and losses on divestiture of assets, as well as other Cenovus-wide costs for general and administrative, financing activities and research costs. As financial instruments are settled, the realized gains and losses are recorded in the reportable segment to which the derivative instrument relates. Eliminations 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. The Corporate and Eliminations segment is attributed to Canada, with the exception of unrealized risk management gains and losses, which have been attributed to the country in which the transacting entity resides.

In 2017, Cenovus disposed of the majority of the crude oil and natural gas assets in the Company's Conventional segment. As such, the results of operations have been classified as a discontinued operation (see Note 11). 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.

The following tabular financial information presents the segmented information first by segment, then by product and geographic location.

A) Results of Operations – Segment and Operational Information

	Oil Sands			Deep Basin			Refining and Marketing		
For the years ended December 31,	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Revenues									
Gross Sales	**7,362**	2,929	3,030	**555**	-	-	**9,852**	8,439	8,805
Less: Royalties	**230**	9	29	**41**	-	-	**-**	-	-
	7,132	2,920	3,001	**514**	-	-	**9,852**	8,439	8,805
Expenses									
Purchased Product	**-**	-	-	**-**	-	-	**8,476**	7,325	7,709
Transportation and Blending	**3,704**	1,721	1,815	**56**	-	-	**-**	-	-
Operating	**934**	501	531	**250**	-	-	**772**	742	754
Production and Mineral Taxes	**-**	-	-	**1**	-	-	**-**	-	-
(Gain) Loss on Risk Management	**307**	(179)	(404)	**-**	-	-	**6**	26	(43)
Operating Margin	**2,187**	877	1,059	**207**	-	-	**598**	346	385
Depreciation, Depletion and Amortization	**1,230**	655	697	**331**	-	-	**215**	211	191
Exploration Expense	**888**	2	67	**-**	-	-	**-**	-	-
Segment Income (Loss)	**69**	220	295	**(124)**	-	-	**383**	135	194

	Corporate and Eliminations			Consolidated		
For the years ended December 31,	**2017**	2016	2015 [(1)]	**2017**	2016	2015
Revenues						
Gross Sales	**(455)**	(353)	(276)	**17,314**	11,015	11,559
Less: Royalties	**-**	-	1	**271**	9	30
	(455)	(353)	(277)	**17,043**	11,006	11,529
Expenses						
Purchased Product	**(443)**	(347)	(335)	**8,033**	6,978	7,374
Transportation and Blending	**(12)**	(6)	(1)	**3,748**	1,715	1,814
Operating	**(7)**	(4)	(4)	**1,949**	1,239	1,281
Production and Mineral Taxes	**-**	-	1	**1**	-	1
(Gain) Loss on Risk Management	**583**	554	195	**896**	401	(252)
Depreciation, Depletion and Amortization	**62**	65	105	**1,838**	931	993
Exploration Expense	**-**	-	-	**888**	2	67
Segment Income (Loss)	**(638)**	(615)	(238)	**(310)**	(260)	251
General and Administrative	**308**	326	335	**308**	326	335
Finance Costs	**645**	390	381	**645**	390	381
Interest Income	**(62)**	(52)	(28)	**(62)**	(52)	(28)
Foreign Exchange (Gain) Loss, Net	**(812)**	(198)	1,036	**(812)**	(198)	1,036
Revaluation (Gain)	**(2,555)**	-	-	**(2,555)**	-	-
Transaction Costs	**56**	-	-	**56**	-	-
Re-measurement of Contingent Payment	**(138)**	-	-	**(138)**	-	-
Research Costs	**36**	36	27	**36**	36	27
(Gain) Loss on Divestiture of Assets	**1**	6	(2,392)	**1**	6	(2,392)
Other (Income) Loss, Net	**(5)**	34	2	**(5)**	34	2
	(2,526)	542	(639)	**(2,526)**	542	(639)
Earnings (Loss) From Continuing Operations Before Income Tax				**2,216**	(802)	890
Income Tax Expense (Recovery)				**(52)**	(343)	(24)
Net Earnings (Loss) From Continuing Operations				**2,268**	(459)	914

(1) The complete results for the 2017 and 2016 Conventional segment have been classified as a discontinued operation. For the 2015 comparative period, the results of operations for certain Conventional segment royalty interest assets disposed of in 2015 have been included in the Corporate and Eliminations segment due to their immaterial nature. The results of operations are as follows: revenues – $60 million, expenses – $5 million, operating margin – $55 million, depreciation, depletion and amortization – $27 million and segment income – $28 million.

B) Revenues by Product

For the years ended December 31,	2017	2016	2015
Upstream			
Crude Oil	**7,184**	2,902	2,971
Natural Gas [1]	**235**	16	22
NGLs	**184**	-	-
Other	**43**	2	8
Refining and Marketing	**9,852**	8,439	8,805
Corporate and Eliminations	**(455)**	(353)	(277)
Revenues From Continuing Operations	**17,043**	11,006	11,529

(1) *In 2017, approximately 14 percent of the natural gas produced by Cenovus's Deep Basin Assets was sold to ConocoPhillips resulting in gross sales of $32 million.*

C) Geographical Information

	Revenues		
For the years ended December 31,	2017	2016	2015
Canada	**9,723**	4,978	4,729
United States	**7,320**	6,028	6,800
Consolidated	**17,043**	11,006	11,529

	Non-Current Assets [1]	
As at December 31,	2017	2016
Canada [2]	**31,756**	14,130
United States	**3,856**	4,179
Consolidated	**35,612**	18,309

(1) *Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), goodwill and other assets.*
(2) *Certain crude oil and natural gas properties of the Conventional and Deep Basin segments, which reside in Canada, have been reclassified as held for sale in 2017 in current assets. 2016 includes $3.1 billion related to the Conventional segment.*

Export Sales

Sales of crude oil, NGLs and natural gas produced or purchased in Canada that have been delivered to customers outside of Canada were $1,713 million (2016 – $974 million; 2015 – $870 million).

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, NGLs, natural gas and refined products for the year ended December 31, 2017, Cenovus had two customers (2016 – three; 2015 – three) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $5,655 million and $1,964 million, respectively (2016 – $4,742 million, $1,623 million and $1,400 million; 2015 – $4,647 million, $1,705 million and $1,545 million), which are included in all of the Company's operating segments.

D) Exploration and Evaluation Assets, Property, Plant and Equipment, Goodwill and Total Assets

	E&E		PP&E		Goodwill		Total Assets	
As at December 31,	2017	2016	2017	2016	2017	2016	2017	2016
Oil Sands	**617**	1,564	**22,320**	8,798	**2,272**	242	**26,799**	11,112
Deep Basin	**3,056**	-	**3,019**	-	**-**	-	**6,694**	-
Conventional	**-**	21	**-**	3,080	**-**	-	**644**	3,196
Refining and Marketing	**-**	-	**3,967**	4,273	**-**	-	**5,432**	6,613
Corporate and Eliminations	**-**	-	**290**	275	**-**	-	**1,364**	4,337
Consolidated	**3,673**	1,585	**29,596**	16,426	**2,272**	242	**40,933**	25,258

E) Capital Expenditures [1]

For the years ended December 31,	**2017**	2016	2015
Capital			
Oil Sands	**973**	604	1,185
Deep Basin	**225**	-	-
Conventional	**206**	171	244
Refining and Marketing	**180**	220	248
Corporate	**77**	31	37
Capital Investment	**1,661**	1,026	1,714
Acquisition Capital			
Oil Sands [2]	**11,614**	11	3
Deep Basin	**6,774**	-	-
Conventional	**-**	-	1
Refining and Marketing	**-**	-	83
Total Capital Expenditures	**20,049**	1,037	1,801

(1) Includes expenditures on PP&E, E&E assets and assets held for sale.
(2) In connection with the Acquisition discussed in Note 5, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by International Financial Reporting Standard 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. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these Consolidated Financial Statements, unless otherwise indicated, all dollars are expressed in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These Consolidated Financial Statements have been prepared in compliance with IFRS.

These Consolidated Financial Statements have been prepared on a historical cost basis, except as detailed in the Company's accounting policies disclosed in Note 3.

These Consolidated Financial Statements were approved by the Board of Directors on February 14, 2018.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

A) Principles of Consolidation

The Consolidated Financial Statements include the accounts of Cenovus and its subsidiaries. Subsidiaries are entities over which the Company has control. Subsidiaries are consolidated from the date of acquisition of control and continue to be consolidated until the date that there is a loss of control. All intercompany transactions, balances, and unrealized gains and losses from intercompany transactions are eliminated on consolidation.

Interests in joint arrangements are classified as either joint operations or joint ventures, depending on the rights and obligations of the parties to the arrangement. Joint operations arise when the Company has rights to the assets and obligations for the liabilities of the arrangement. The Company's Refining activities are conducted through the joint operation WRB Refining LP ("WRB") and, accordingly, the accounts reflect the Company's share of the assets, liabilities, revenues and expenses. Prior to May 17, 2017, FCCL was accounted for as a joint operation. Subsequent to the Acquisition, Cenovus controls FCCL, and accordingly, FCCL has been consolidated.

B) Foreign Currency Translation

Functional and Presentation Currency

The Company's presentation currency is Canadian dollars. The accounts of the Company's foreign operations that have a functional currency different from the Company's presentation currency are translated into the Company's presentation currency at period-end exchange rates for assets and liabilities, and using average rates over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in other comprehensive income ("OCI") as cumulative translation adjustments.

When the Company disposes of an entire interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign

operation are recognized in net earnings. When the Company disposes of part of an interest in a foreign operation that continues to be a subsidiary, a proportionate amount of gains and losses accumulated in OCI is allocated between controlling and non-controlling interests.

Transactions and Balances

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the period-end date. Any gains or losses are recorded in the Consolidated Statements of Earnings.

C) Revenue Recognition

Revenues associated with the sales of Cenovus's crude oil, NGLs, natural gas, and petroleum and refined products are recognized when the significant risks and rewards of ownership have been transferred to the customer, the sales price and costs can be measured reliably and it is probable that the economic benefits will flow to the Company. This is generally met when title passes from the Company to its customer. Revenues from the production of crude oil, NGLs and natural gas represent the Company's share, net of royalty payments to governments and other mineral interest owners.

Processing income and revenue from fee-for-service hydrocarbon trans-loading services is recognized in the period the service is provided.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded on a net basis. Revenues associated with the services provided as agent are recorded as the services are provided.

D) Transportation and Blending

The costs associated with the transportation of crude oil, NGLs and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

E) Exploration Expense

Costs incurred prior to obtaining the legal right to explore (pre-exploration costs) are expensed in the period in which they are incurred as exploration expense.

Costs incurred after the legal right to explore is obtained are initially capitalized. If it is determined that the field/project/area is not technically feasible and commercially viable or if the Company decides not to continue the exploration and evaluation activity, the unrecoverable accumulated costs are expensed as exploration expense.

F) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component and an other post-employment benefit plan ("OPEB").

Pension expense for the defined contribution pension is recorded as the benefits are earned.

The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The amount recognized in other liabilities on the Consolidated Balance Sheets for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets. Any surplus resulting from this calculation is limited to the present value of any economic benefits available in the form of refunds from the plans or reductions in future contributions to the plans.

Changes in the defined benefit obligation from service costs, net interest and remeasurements are recognized as follows:

- Service costs, including current service costs, past service costs, gains and losses on curtailments, and settlements, are recorded with pension benefit costs.
- Net interest is calculated by applying the same discount rate used to measure the defined benefit obligation at the beginning of the annual period to the net defined benefit asset or liability measured. Interest expense and interest income on net post-employment benefit liabilities and assets are recorded with pension benefit costs in operating, and general and administrative expenses, as well as PP&E and E&E assets.
- Remeasurements, composed of actuarial gains and losses, the effect of changes to the asset ceiling (excluding interest) and the return on plan assets (excluding interest income), are charged or credited to equity in OCI in the period in which they arise. Remeasurements are not reclassified to net earnings in subsequent periods.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the associated salaries of the employees rendering the service are recorded.

G) Income Taxes

Income taxes comprise current and deferred taxes. Income taxes are provided for on a non-discounted basis at amounts expected to be paid using the tax rates and laws that have been enacted or substantively enacted at the Consolidated Balance Sheet date.

Cenovus follows the liability method of accounting for income taxes, where deferred income taxes are recorded for the effect of any temporary difference between the accounting and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets are realized or liabilities are settled. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs, except when it relates to items charged or credited directly to equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is provided on temporary differences arising from investments in subsidiaries except in the case where the timing of the reversal of the temporary difference is controlled by the Company and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction. Deferred income tax assets and liabilities are presented as non-current.

H) Net Earnings per Share Amounts

Basic net earnings per share is computed by dividing net earnings by the weighted average number of common shares outstanding during the period. Diluted net earnings per share is calculated giving effect to the potential dilution that would occur if stock options or other contracts to issue common shares were exercised or converted to common shares. The treasury stock method is used to determine the dilutive effect of stock options and other dilutive instruments. The treasury stock method assumes that proceeds received from the exercise of in-the-money stock options are used to repurchase common shares at the average market price. For those contracts that may be settled in cash or in shares at the holder's option, the more dilutive of cash settlement and share settlement is used in calculating diluted earnings per share.

I) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with a maturity of three months or less.

J) Inventories

Product inventories are valued at the lower of cost and net realizable value on a first-in, first-out or weighted average cost basis. The cost of inventory includes all costs incurred in the normal course of business to bring each product to its present location and condition. Net realizable value is the estimated selling price in the ordinary course of business less any expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized. The write-down may be reversed in a subsequent period if circumstances which caused it no longer exist and the inventory is still on hand.

K) Exploration and Evaluation Assets

Costs incurred after the legal right to explore an area has been obtained, and before technical feasibility and commercial viability of the field/project/area have been established, are capitalized as E&E assets. These costs include license acquisition, geological and geophysical, drilling, sampling, decommissioning and other directly attributable internal costs. E&E assets are not depreciated and are carried forward until technical feasibility and commercial viability of the field/project/area is established or the assets are determined to be impaired. E&E costs are subject to regular technical, commercial and Management review to confirm the continued intent to develop the resources.

Once technical feasibility and commercial viability have been established, the carrying value of the E&E asset is tested for impairment. The carrying value, net of any impairment loss, is then reclassified as PP&E.

Any gains or losses from the divestiture of E&E assets are recognized in net earnings.

L) Property, Plant and Equipment

General

PP&E is stated at cost less accumulated depreciation, depletion and amortization ("DD&A"), and net of any impairment losses. Expenditures related to renewals or betterments that improve the productive capacity or extend the life of an asset are capitalized. Maintenance and repairs are expensed as incurred. Land is not depreciated.

Any gains or losses from the divestiture of PP&E are recognized in net earnings.

Development and Production Assets

Development and production assets are capitalized on an area-by-area basis and include all costs associated with the development and production of crude oil and natural gas properties, as well as any E&E expenditures incurred in finding reserves of crude oil, NGLs or natural gas transferred from E&E assets. Capitalized costs include directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs directly associated with the acquisition of, the exploration for, and the development of crude oil and natural gas reserves.

Costs accumulated within each area are depleted using the unit-of-production method based on estimated proved reserves determined using forward prices and costs. For the purpose of this calculation, natural gas is converted to crude oil on an energy equivalent basis. Costs subject to depletion include estimated future costs to be incurred in developing proved reserves.

Exchanges of development and production assets are measured at fair value unless the transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up, can be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

Other Upstream Assets

Other upstream assets include information technology assets used to support the upstream business. These assets are depreciated on a straight-line basis over their useful lives of three years.

Refining Assets

The initial acquisition costs of refining PP&E are capitalized when incurred. Costs include the cost of constructing or otherwise acquiring the equipment or facilities, the cost of installing the asset and making it ready for its intended use, the associated decommissioning costs and, for qualifying assets, borrowing costs.

Refining assets are depreciated on a straight-line basis over the estimated service life of each component of the refinery. The major components are depreciated as follows:

- Land improvements and buildings — 25 to 40 years
- Office equipment and vehicles — 3 to 20 years
- Refining equipment — 5 to 35 years

The residual value, method of amortization and the useful life of each component are reviewed annually and adjusted on a prospective basis, if appropriate.

Other Assets

Costs associated with the crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft are carried at cost and depreciated on a straight-line basis over the estimated service lives of the assets, which range from three to 40 years.

The residual value, method of amortization and the useful lives of the assets are reviewed annually and adjusted on a prospective basis, if appropriate.

M) Impairment

Non-Financial Assets

PP&E and E&E assets are reviewed separately for indicators of impairment quarterly or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

If indicators of impairment exist, the recoverable amount of the cash-generating unit ("CGU") is estimated as the greater of value-in-use ("VIU") and fair value less costs of disposal ("FVLCOD"). VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of a CGU or an asset. FVLCOD is determined by estimating the discounted after-tax future net cash flows. For Cenovus's upstream assets, FVLCOD is based on the discounted after-tax cash flows of reserves and resources using forward prices and costs, consistent with Cenovus's independent qualified reserves evaluators ("IQREs"), and may consider an evaluation of comparable asset transactions.

E&E assets are allocated to a related CGU containing development and production assets for the purposes of testing for impairment. Goodwill is allocated to the CGUs to which it contributes to the future cash flows.

If the recoverable amount of the CGU is less than the carrying amount, an impairment loss is recognized. An impairment loss is allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amounts of the other assets in the CGU. Goodwill impairments are not reversed.

Impairment losses on PP&E and E&E assets are recognized in the Consolidated Statements of Earnings as additional DD&A and exploration expense, respectively.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

Financial Assets

At each reporting date, the Company assesses whether there are any indicators that its financial assets are impaired. An impairment loss is only recognized if there is objective evidence of impairment, the loss event has an impact on future cash flows and the loss can be reliably estimated.

Evidence of impairment may include default or delinquency by a debtor or indicators that the debtor may enter bankruptcy. For equity securities, a significant or prolonged decline in the fair value of the security below cost is evidence that the assets are impaired.

An impairment loss on a financial asset carried at amortized cost is calculated as the difference between the amortized cost and the present value of the future cash flows discounted at the asset's original effective interest rate. The carrying amount of the asset is reduced through the use of an allowance account. Impairment losses on financial assets carried at amortized cost are reversed through net earnings in subsequent periods if the amount of the loss decreases.

N) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases. At inception, a leased asset within PP&E and a corresponding lease obligation are recognized. The leased asset is depreciated over the shorter of the estimated useful life of the asset or the lease term.

O) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured at their fair value at the date of acquisition. Any excess of the purchase price plus any non-controlling interest over the fair value of the net assets acquired is recognized as goodwill. Any deficiency of the purchase price over the fair value of the net assets acquired is credited to net earnings.

At acquisition, goodwill is allocated to each of the CGUs to which it relates. Subsequent measurement of goodwill is at cost less any accumulated impairment losses.

Contingent consideration transferred in a business combination is measured at fair value on the date of acquisition and classified as a financial liability or equity. Contingent consideration classified as a liability is re-measured at fair value at each reporting date, with changes in fair value recognized in net earnings. Payments are classified as cash used in investing activities until the cumulative payments exceed the acquisition date fair value of the liability. Cumulative payments in excess of the acquisition date fair value are classified as cash used in operating activities. Contingent consideration classified as equity are not re-measured and settlements are accounted for within equity.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings.

P) Provisions

General

A provision is recognized if, as a result of a past event, the Company has a present obligation, legal or constructive, that can be estimated reliably, and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, provisions are determined by discounting the expected future cash flows at a pre-tax credit-adjusted rate that reflects the current market assessments of the time value of money and the risks specific to the liability. The increase in the provision due to the passage of time is recognized as a finance cost in the Consolidated Statements of Earnings.

Decommissioning Liabilities

Decommissioning liabilities include those legal or constructive obligations where the Company will be required to retire tangible long-lived assets such as producing well sites, upstream processing facilities, refining facilities and the crude-by-rail terminal. The amount recognized is the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. A corresponding asset equal to the initial estimate of the liability is capitalized as part of the cost of the related long-lived asset. Changes in the estimated liability resulting from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. The amount capitalized in PP&E is depreciated over the useful life of the related asset.

Actual expenditures incurred are charged against the accumulated liability.

Q) Share Capital

Common shares are classified as equity. Transaction costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any income taxes.

R) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans which include stock options with associated net settlement rights ("NSRs"), stock options with associated tandem stock appreciation rights ("TSARs"), performance share units ("PSUs"), restricted share units ("RSUs") and deferred share units ("DSUs"). Stock-based compensation costs are recorded in general and administrative expense, or E&E and PP&E when directly related to exploration or development activities.

Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model and are not revalued at each reporting date. The fair value is recognized as stock-based compensation costs over the vesting period, with a corresponding increase recorded as paid in surplus in Shareholders' Equity. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Tandem Stock Appreciation Rights

TSARs are accounted for as liability instruments, which are measured at fair value at each period end using the Black-Scholes-Merton valuation model. The fair value is recognized as stock-based compensation costs over the vesting period. When options are settled for cash, the liability is reduced by the cash settlement paid. When options are settled for common shares, the cash consideration received by the Company and the previously recorded liability associated with the option are recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair values are recognized as stock-based compensation costs in the period they occur.

S) Financial Instruments

The Company's financial assets include cash and cash equivalents, accounts receivable and accrued revenues, risk management assets, investments in the equity of private companies and long-term receivables. The Company's financial liabilities include accounts payable and accrued liabilities, contingent payment, risk management liabilities, short-term borrowings and long-term debt.

Financial instruments are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. A financial asset is derecognized when the rights to receive cash flows from the asset have expired or have been transferred and the Company has transferred substantially all the risks and rewards of ownership. A financial liability is derecognized when the obligation is discharged, cancelled or expired. When an existing financial liability is replaced by another from the same counterparty with substantially different terms, or the terms of an existing liability are substantially modified, this exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability. The difference in the carrying amounts of the liabilities is recognized in the Consolidated Statements of Earnings.

Financial instruments are classified as either "fair value through profit and loss", "loans and receivables", "held-to-maturity investments", "available for sale financial assets" or "financial liabilities measured at amortized cost". The Company determines the classification of its financial instruments at initial recognition. Financial instruments are

initially measured at fair value except in the case of "financial liabilities measured at amortized cost", which are initially measured at fair value net of directly attributable transaction costs.

As required by IFRS, the Company characterizes its fair value measurements into a three-level hierarchy depending on the degree to which the inputs are observable, as follows:

- Level 1 inputs are quoted prices in active markets for identical assets and liabilities;
- Level 2 inputs are inputs, other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly; and
- Level 3 inputs are unobservable inputs for the asset or liability.

Fair Value Through Profit or Loss

Financial assets and financial liabilities at "fair value through profit or loss" are either "held-for-trading" or have been "designated at fair value through profit or loss." In both cases, the financial assets and financial liabilities are measured at fair value with changes in fair value recognized in net earnings.

Risk management assets and liabilities are derivative financial instruments classified as "held-for-trading" unless designated for hedge accounting. Derivative instruments that do not qualify as hedges, or are not designated as hedges, are recorded using mark-to-market accounting whereby instruments are recorded in the Consolidated Balance Sheets as either an asset or liability with changes in fair value recognized in net earnings as a (gain) loss on risk management. Derivative financial instruments are not used for speculative purposes.

The Company has classified its contingent payment as "fair value through profit or loss."

Loans and Receivables

"Loans and receivables" are financial assets with fixed or determinable payments that are not quoted in an active market. After initial measurement, these assets are measured at amortized cost at the settlement date using the effective interest method of amortization. "Loans and receivables" comprise cash and cash equivalents, accounts receivable and accrued revenues, and long-term receivables. Gains and losses on "loans and receivables" are recognized in net earnings when the "loans and receivables" are derecognized or impaired.

Available for Sale Financial Assets

"Available for sale financial assets" are measured at fair value, with changes in fair value recognized in OCI. When an active market is non-existent, fair value is determined using valuation techniques. When fair value cannot be reliably measured, such assets are carried at cost. Available for sale financial assets comprise investments in the equity of private companies that the Company does not control or have significant influence over.

Financial Liabilities Measured at Amortized Cost

These financial liabilities are measured at amortized cost at the settlement date using the effective interest method of amortization. Financial liabilities measured at amortized cost comprise accounts payable and accrued liabilities, short-term borrowings and long-term debt. Long-term debt transaction costs, premiums and discounts are capitalized within long-term debt or as a prepayment and amortized using the effective interest method.

T) Reclassification

Certain information provided for prior years has been reclassified to conform to the presentation adopted in 2017.

U) Recent Accounting Pronouncements

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, the Company has elected to measure these investments as FVOCI. As such, all fair value gains or losses will be recorded in 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. Management does not expect a material change to its impairment provision as at January 1, 2018.

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. The Company 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. Cenovus intends 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. The Company 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 12 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 the Company's Consolidated Balance Sheets due to material operating lease commitments. Cenovus will adopt IFRS 16 effective January 1, 2019. The Company intends 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 23, *"Uncertainty Over Income Tax Treatments"* ("IFRIC 23"). 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.

4. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities, and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) 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 the Company's Consolidated Financial Statements.

Joint Arrangements

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

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

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

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

Exploration and Evaluation Assets

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

Identification of Cash-Generating Units

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

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recorded in the period in which the estimates are revised. The following are the key assumptions about the future and other key sources of estimation at the end of the reporting period that changes to could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the recoverable quantities of hydrocarbons, the cost of the development of the required infrastructure to recover the hydrocarbons, production costs, estimated selling price of the hydrocarbons produced, royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test fair value less costs to sell and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands and Deep Basin segments. The Company's reserves are evaluated annually and reported to the Company by its IQREs.

Recoverable Amounts

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

Decommissioning Costs

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

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

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

Income Tax Provisions

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

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation

including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

5. ACQUISITION

FCCL and Deep Basin Acquisition

A) Summary of the Acquisition

On May 17, 2017, Cenovus acquired ConocoPhillips' 50 percent interest in FCCL and the majority of ConocoPhillips' Deep Basin Assets in Alberta and British Columbia (the "Acquisition"). The Acquisition provides Cenovus with control over the Company's oil sands operations, doubles the Company's oil sands production, and almost doubles the Company's proved bitumen reserves. The Deep Basin Assets provide a second core operating area with more than three million net acres of land, exploration and production assets, and related infrastructure in Alberta and British Columbia.

The Acquisition has been accounted for using the acquisition method pursuant to IFRS 3. Under the acquisition method, assets and liabilities are recorded at their fair values on the date of acquisition and the total consideration is allocated to the tangible and intangible assets acquired and liabilities assumed. The excess of consideration given over the fair value of the net assets acquired has been recorded as goodwill.

B) Identifiable Assets Acquired and Liabilities Assumed

The final purchase price allocation is based on Management's best estimate of fair value and has been retrospectively adjusted to reflect new information obtained between May 17, 2017 and December 31, 2017 about conditions that existed at the acquisition date. As a result of these adjustments, the final purchase price allocation includes an increase of $912 million to PP&E, $56 million to inventory, and $16 million to accounts receivable and accrued revenues, as well as an $822 million decrease to E&E assets. Goodwill from the Acquisition was reduced to $2,030 million and the revaluation gain increased to $2,555 million. These adjustments also resulted in a $9 million increase to the deferred income tax liability.

The following table summarizes the recognized amounts of assets acquired and liabilities assumed at the date of the Acquisition.

	Notes	
100 Percent of the Identifiable Assets Acquired and Liabilities Assumed for FCCL		
Cash		**880**
Accounts Receivable and Accrued Revenues		**964**
Inventories		**345**
E&E Assets	17	**491**
PP&E	18	**22,717**
Other Assets		**27**
Accounts Payable and Accrued Liabilities		**(445)**
Decommissioning Liabilities	24	**(277)**
Other Liabilities		**(8)**
Deferred Income Taxes		**(2,506)**
		22,188
Recognized Amounts of Identifiable Assets Acquired and Liabilities Assumed for Deep Basin		
Accounts Receivable and Accrued Revenues		**16**
Inventories		**14**
E&E Assets	17	**3,117**
PP&E	18	**3,600**
Accounts Payable and Accrued Liabilities		**(6)**
Decommissioning Liabilities	24	**(667)**
		6,074
Total Identifiable Net Assets		**28,262**

The fair value of acquired accounts receivables and accrued revenues was $980 million. As at December 31, 2017, $964 million has been received and the remainder is expected to be collected.

C) Total Consideration

Total consideration for the Acquisition consisted of US$10.6 billion in cash and 208 million Cenovus common shares plus closing adjustments. At the same time, Cenovus agreed to make certain quarterly contingent payments to ConocoPhillips during the five years subsequent to May 17, 2017 if crude oil prices exceed a specific threshold. The following table summarizes the fair value of the consideration:

Common Shares	**2,579**
Cash	**15,005**
	17,584
Estimated Contingent Payment (Note 22)	**361**
Total Consideration	**17,945**

At the date of closing, the Company issued 208 million common shares to ConocoPhillips that were accounted for at $12.40 per share, the estimated fair value for accounting purposes.

Consideration paid in cash was US$10.6 billion, before closing adjustments, and was financed through a bought-deal common share offering (see Note 27) and an offering in the United States for senior unsecured notes (see Note 23). In addition, Cenovus borrowed $3.6 billion under a committed asset sale bridge credit facility (see Note 23). The remainder of the cash purchase price was funded with cash on hand and a draw on Cenovus's existing committed credit facility.

The estimated contingent payment related to oil sands production reflects that Cenovus agreed to make quarterly payments to ConocoPhillips during the five years subsequent to the closing date for quarters in which the average Western Canadian Select ("WCS") crude oil price exceeds $52.00 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52.00 per barrel. There are no maximum payment terms.

The calculation of any contingent payment 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 terms of the contingent payment agreement allow Cenovus to retain 80 percent to 85 percent of the WCS prices above $52.00 per barrel, based on gross production capacity at Foster Creek and Christina Lake at the time of the Acquisition. As production capacity increases with future expansions, the percentage of upside available to Cenovus will increase further.

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, which assumes the probability distribution for WCS is based on the volatility of West Texas Intermediate ("WTI") options, volatility of Canadian-U.S. foreign exchange rate options and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 2.9 percent. The contingent payment will be re-measured at fair value at each reporting date with changes in fair value recognized in net earnings (see Note 22).

D) Goodwill

Goodwill arising from the Acquisition has been recognized as follows:

	Notes	
Total Purchase Consideration	4C	**17,945**
Fair Value of Pre-Existing 50 Percent Ownership Interest in FCCL		**12,347**
Fair Value of Identifiable Net Assets	4B	**(28,262)**
Goodwill		**2,030**

Fair Value of Pre-Existing 50 Percent Ownership Interest in FCCL

Prior to the Acquisition, Cenovus's 50 percent interest in FCCL was jointly controlled with ConocoPhillips and met the definition of a joint operation under IFRS 11 and 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 from the date of acquisition. As required by IFRS 3, when an acquirer achieves control in stages, the previously held interest is re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings. The acquisition-date fair value of the previously held interest was $12.3 billion and has been included in the measurement of the total consideration transferred. The carrying value of the FCCL assets was $9.7 billion. As a result, Cenovus recognized a non-cash revaluation gain of $2.6 billion ($1.9 billion, after-tax) on the re-measurement to fair value of its existing interest in FCCL.

Goodwill was recorded in connection with deferred tax liabilities arising from the difference between the purchase price allocated to the FCCL assets and liabilities based on fair value and the tax basis of these assets and liabilities. In addition, the consideration paid for FCCL included a control premium, which resulted in a higher value compared to the fair value of the net assets acquired.

E) Acquisition-Related Costs

The Company incurred $56 million of Acquisition-related costs, excluding common share and debt issuance costs. These costs have been included in transaction costs in the Consolidated Statements of Earnings.

Debt issuance costs related to the Acquisition financing were $72 million. These costs are netted against the carrying amount of the debt and amortized using the effective interest method.

F) Transitional Services

Under the purchase and sales agreement, Cenovus and ConocoPhillips agreed to certain transitional services where ConocoPhillips provided certain day-to-day services required by Cenovus for a period of approximately nine months. These transactions were in the normal course of operations and have been measured at the exchange amounts.

Costs related to the transitional services of approximately $40 million were recorded in general and administrative expenses.

G) Revenue and Profit Contribution

The acquired business contributed revenues of $3.3 billion and net earnings of $172 million for the period from May 17, 2017 to December 31, 2017.

If the closing of the Acquisition had occurred on January 1, 2017, Cenovus's consolidated pro forma revenue and net earnings for the twelve months ended December 31, 2017 would have been $19.0 billion and $3.5 billion, respectively. These amounts have been calculated using results from the acquired business and adjusting them for:

- Differences in accounting policies;
- Additional finance costs that would have been incurred if the amounts drawn on the Company's committed asset sale bridge credit facility and the senior unsecured notes issued to fund the Acquisition had occurred on January 1, 2017;
- Additional DD&A that would have been charged assuming the fair value adjustments to PP&E and E&E assets had applied from January 1, 2017;
- Accretion on the decommissioning liability if it had been assumed on January 1, 2017; and
- The consequential tax effects.

This pro forma information is not necessarily indicative of the results that would have been obtained if the Acquisition had actually occurred on January 1, 2017.

Crude-by-Rail Terminal Acquisition

In August 2015, the Company completed the acquisition of a crude-by-rail terminal for cash consideration of $75 million, plus adjustments. The transaction was accounted for using the acquisition method of accounting. In connection with the acquisition, the Company assumed an associated decommissioning liability of $4 million, working capital of $1 million and net transportation commitments of $92 million. Transaction costs associated with the acquisition were expensed. These assets, related liabilities and results of operations are reported in the Refining and Marketing segment.

6. FINANCE COSTS

For the years ended December 31,	**2017**	2016	2015
Interest Expense – Short-Term Borrowings and Long-Term Debt	**571**	341	328
Unwinding of Discount on Decommissioning Liabilities (Note 24)	**48**	28	25
Other	**26**	21	28
	645	390	381

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2017**	2016	2015
Unrealized Foreign Exchange (Gain) Loss on Translation of:			
U.S. Dollar Debt Issued From Canada	**(665)**	(196)	1,064
Other	**(192)**	7	33
Unrealized Foreign Exchange (Gain) Loss	**(857)**	(189)	1,097
Realized Foreign Exchange (Gain) Loss	**45**	(9)	(61)
	(812)	(198)	1,036

8. DIVESTITURES

In 2017, the Company completed the sale of the majority of its Conventional segment crude oil and natural gas properties for gross proceeds of $3.2 billion. A net gain of $1.3 billion was recorded on the divestitures. For further information see Note 11.

In 2016, the Company completed the sale of land to an unrelated third party for cash proceeds of $8 million, resulting in a loss of $5 million. The Company also sold equipment at a loss of $1 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

In 2015, the Company completed the sale of Heritage Royalty Limited Partnership ("HRP"), a wholly-owned subsidiary, to a third party for gross cash proceeds of $3.3 billion, resulting in a gain of $2.4 billion. HRP was a royalty business consisting of royalty interest and mineral fee title lands in Alberta, Saskatchewan and Manitoba. These assets, related liabilities and results of operations were reported in the Conventional segment. In 2017, the remaining Conventional segment was classified as a discontinued operation.

The divestiture of HRP gave rise to a taxable gain for which the Company recognized a current tax expense of $391 million. The majority of HRP's assets had been acquired at a nominal cost and, as such, had minimal benefit from tax depreciation in prior years. For this reason, the current tax expense associated with the divestiture was specifically identifiable; therefore, it was classified as an investing activity in the Consolidated Statements of Cash Flows.

In addition, the Company divested of an office building in 2015, recording a gain of $16 million.

9. OTHER (INCOME) LOSS, NET

As at December 31, 2016, due to the Government of Canada's decision to reject the Northern Gateway Pipeline project, the Company wrote off $23 million of capitalized costs associated with its funding support unit in Northern Gateway Pipeline. In addition, $7 million of costs associated with termination were recorded and $7 million (2015 – $nil) of certain investments in private equity companies were written off.

10. IMPAIRMENT CHARGES AND REVERSALS

A) Cash-Generating Unit Net Impairments

On a quarterly basis, the Company assesses its CGUs for indicators of impairment or when facts and circumstances suggest the carrying amount may exceed its recoverable amount. Goodwill is tested for impairment at least annually.

2017 Upstream Impairments

As indicators of impairment were noted for the Company's upstream assets due to a decline in forward commodity prices since the Acquisition, the Company tested its upstream CGUs for impairment. As at December 31, 2017, the Company 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 in the Deep Basin segment. Future cash flows for the CGU declined due to lower forward crude oil prices and revisions to the development plan. As at December 31, 2017, the recoverable amount of the Clearwater CGU was estimated to be approximately $295 million.

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on FVLCOD or an evaluation of comparable asset transactions. The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Key assumptions in the determination of future cash flows from reserves include crude oil and natural gas prices, costs to develop and the discount rate. All reserves have been evaluated as at December 31, 2017 by the IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward prices as at December 31, 2017, used to determine future cash flows from crude oil, NGLs 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)]	2.43	2.77	3.19	3.48	3.67	2.0%

(1) Alberta Energy Company ("AECO") natural gas.
(2) 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.

For the purpose of impairment testing, goodwill is allocated to the CGU to which it relates. There were no goodwill impairments for the twelve months ended December 31, 2017.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or forward commodity prices would have on impairment testing for the following CGUs:

	Increase (Decrease) to Impairment			
	One Percent Increase in the Discount Rate	**One Percent Decrease in the Discount Rate**	**Five Percent Increase in the Forward Price Estimates [(1)]**	**Five Percent Decrease in the Forward Price Estimates**
Clearwater	**27**	**(30)**	**(56)**	**65**
Primrose	**-**	**-**	**-**	**-**
Christina Lake	**-**	**-**	**-**	**-**
Narrows Lake	**312**	**-**	**-**	**333**

(1) The $56 million represents the impairment loss as at December 31, 2017 that could be reversed in future periods.

2016 Net Upstream Impairments

As at December 31, 2016, the recoverable value of the Northern Alberta CGU was estimated to be $1.1 billion. Earlier in 2016 and 2015, impairment losses of $380 million and $184 million, respectively, were recorded primarily due to a decline in long-term heavy crude oil prices and a slowing of the development plan. In the fourth quarter of 2016, the Company reversed $400 million of impairment losses, net of the DD&A that would have been recorded had no impairments been recorded. The reversal arose due to the increase in the CGU's estimated recoverable amount caused by an average reduction in expected future operating costs of five percent and lower future development costs, partially offset by a decline in estimated reserves. The impairment losses and subsequent reversal were recorded as DD&A in the Conventional segment, which has been classified as a discontinued operation (see Note 11). The Northern Alberta CGU included the Pelican Lake and Elk Point producing assets and other emerging assets in the exploration and evaluation stage.

As at December 31, 2016, the recoverable amount of the Suffield CGU PP&E was estimated to be $548 million. Earlier in 2016, an impairment loss of $65 million was recognized due to lower long-term forward natural gas and heavy crude oil prices. In the fourth quarter of 2016, the Company reversed the full amount of the impairment losses, net of the DD&A that would have been recorded had no impairment been recorded ($62 million). The reversal arose due to a decline in expected future royalties increasing the estimated recoverable amount of the

CGU. The impairment loss and the subsequent reversal were recorded as DD&A in the Conventional segment, which has been classified as a discontinued operation (see Note 11). The Suffield CGU included production of natural gas and heavy crude oil in Alberta on the Canadian Forces Base.

There were no goodwill impairments for the twelve months ended December 31, 2016.

Key Assumptions

The fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. Forward prices as at December 31, 2016 used to determine future cash flows from crude oil and natural gas reserves were:

	2017	2018	2019	2020	2021	Average Annual Increase Thereafter
WTI (US$/barrel)	55.00	58.70	62.40	69.00	75.80	2.0%
WCS (C$/barrel)	53.70	58.20	61.90	66.50	71.00	2.0%
AECO (C$/Mcf) [1]	3.40	3.15	3.30	3.60	3.90	2.2%

(1) *Assumes gas heating value of one million British Thermal Units per thousand cubic feet.*

2015 Upstream Impairments

As at December 31, 2015, the Company determined that the carrying amount of the Northern Alberta CGU exceeded its recoverable amount, resulting in an impairment loss of $184 million. The impairment was recorded as additional DD&A in the Conventional segment, which has been classified as a discontinued operation (see Note 11). Future cash flows for the CGU declined due to lower forward crude oil prices, a decline in reserves estimates and a slowing down of the development plan. This was partially offset by lower future development and operating costs.

The recoverable amount was determined using FVLCOD. The fair value of producing properties was calculated based on discounted after-tax cash flows of proved and probable reserves using forward prices and cost estimates, prepared by Cenovus's IQREs (Level 3). Future cash flows were estimated using a two percent inflation rate and discounted using a rate of 10 percent. As at December 31, 2015, the recoverable amount of the Northern Alberta CGU was estimated to be approximately $1.5 billion.

There were no goodwill impairments for the twelve months ended December 31, 2015.

B) Asset Impairments and Writedowns

Exploration and Evaluation Assets

For the year ended December 31, 2017, Management wrotedown certain E&E assets, as their carrying values were not considered to be recoverable. As a result, $888 million of previously capitalized costs were recorded as exploration expense. These assets reside primarily in the Borealis CGU within the Oil Sands segment.

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.

In 2016, $2 million of previously capitalized E&E costs were written off and recorded as exploration expense in the Oil Sands segment.

In 2015, $138 million of previously capitalized E&E costs were written off and recorded as exploration expense. This writedown included $67 million and $71 million within the Oil Sands and Conventional segments, respectively.

Property, Plant and Equipment, Net

In 2017, the Company recorded an impairment loss of $21 million related to equipment that was written down to its recoverable amount. The impairment loss relates to the Oil Sands segment.

In 2016, the Company recorded an impairment loss of $20 million primarily related to equipment that was written down to its recoverable amount. This impairment was recorded as additional DD&A in the Conventional segment, which has been classified as a discontinued operation. The Company also recorded an impairment loss of $16 million related to preliminary engineering costs associated with a project that was cancelled and equipment that was written down to its recoverable amount. This impairment loss was recorded as additional DD&A in the Oil Sands segment. Leasehold improvements of $4 million were also written off and recorded as additional DD&A in the Corporate and Eliminations segment.

In 2015, the Company impaired a sulphur recovery facility for $16 million, which was recorded as additional DD&A in the Oil Sands segment. The Company did not have future plans for the assets and did not believe it would recover the carrying amount through a sale.

11. ASSETS HELD FOR SALE AND DISCONTINUED OPERATIONS

In the second quarter of 2017, the Company announced its intention to divest of its Conventional segment which included its heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and conventional crude oil, natural gas and NGLs assets in the Suffield and Palliser areas in southern Alberta. The associated assets and liabilities were consequently presented as held for sale and the results of operations reported as a discontinued operation.

A) Results of Discontinued Operations

In 2017, the Company sold the majority of its Conventional segment assets for total gross cash proceeds of $3.2 billion before closing adjustments. Details of the asset sales are as follows.

Pelican Lake

On September 29, 2017, the Company completed the sale of its Pelican Lake heavy oil operations, as well as other miscellaneous assets in northern Alberta, for cash proceeds of $975 million before closing adjustments. A before-tax loss on discontinuance of $623 million was recorded on the sale.

Palliser

On December 7, 2017, Cenovus completed the sale of its Palliser crude oil and natural gas operations in southern Alberta for cash proceeds of $1.3 billion before closing adjustments. A before-tax gain on discontinuance of $1.6 billion was recorded on the sale.

Weyburn

On December 14, 2017, the Company completed the sale of its Weyburn assets in southern Saskatchewan for cash proceeds of $940 million before closing adjustments. A before-tax gain on discontinuance of $276 million was recorded on the sale.

Suffield

On September 25, 2017, Cenovus entered into an agreement to sell its Suffield crude oil and natural gas operations in southern Alberta for cash proceeds of $512 million, before closing adjustments. The sale closed on January 5, 2018. The Company anticipates a before-tax gain of approximately $350 million to be recorded in 2018. The agreement includes a deferred purchase price adjustment ("DPPA") that could provide Cenovus with purchase price adjustments of up to $36 million if the average crude oil and natural gas prices meet certain thresholds over the next two years.

The DPPA is a two year agreement that commences on close. Under the purchase and sale agreement, Cenovus is entitled to receive cash for each month in which the average daily price of WTI is above US$55 per barrel or the price of Henry Hub natural gas is above US$3.50 per million British thermal units. Monthly cash payments are capped at $375 thousand and $1.125 million for crude oil and natural gas, respectively. The DPPA will be accounted for as a financial option and fair valued at each reporting date. The fair value of the DPPA on the date of close was $7 million.

The following table presents the results of discontinued operations, including asset sales:

For the years ended December 31,	**2017**	2016	2015
Revenues			
Gross Sales	**1,309**	1,267	1,648
Less: Royalties	**174**	139	113
	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 (Loss) on Discontinuance [(1)]	**938**	-	-
Net Earnings (Loss) From Discontinued Operations	**1,098**	(86)	(296)

(1) Net of deferred tax expense of $347 million in 2017.

B) Cash Flows From Discontinued Operations

Cash flows from discontinued operations reported in the Consolidated Statement of Cash Flows are:

For the years ended December 31,	**2017**	2016	2015
Cash From Operating Activities	**448**	435	778
Cash From (Used in) Investing Activities	**2,993**	(168)	(243)
Net Cash Flow	**3,441**	267	535

C) Assets and Liabilities Held for Sale

In the fourth quarter of 2017, the Company announced its intention to market for sale a package of non-core Deep Basin assets in the East Clearwater area and a portion of the West Clearwater assets. The assets have been classified as held for sale and recorded at the lesser of their carrying amount and their fair value less cost to sell. Assets and liabilities held for sale also include the Suffield operations, which were sold on January 5, 2018. No impairments were recorded on the assets held for sale as at December 31, 2017.

As at December 31, 2017	**E&E Assets** (Note 17)	**PP&E** (Note 18)	**Decommissioning Liabilities** (Note 24)
Conventional	**-**	**568**	**454**
Deep Basin	**46**	**434**	**149**
	46	**1,002**	**603**

12. INCOME TAXES

The provision for income taxes is:

For the years ended December 31,	**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)
Tax Expense (Recovery) From Continuing Operations	**(52)**	(343)	(24)

In 2017 and 2016, the Company recorded a current tax recovery due to the carryback of losses for income tax purposes and prior year adjustments. A deferred tax expense was recorded in 2017 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 percent to 21 percent reducing the Company's deferred income tax liability and the impact of E&E asset writedowns.

In 2015, the Company recorded a deferred tax recovery of $415 million arising from an adjustment to the tax basis of the refining assets. The increase in tax basis was a result of the Company's partner recognizing a taxable gain on its interest in WRB which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. This was partially offset by an increase in the deferred tax expense as a result of a two percent increase in the Alberta corporate income tax rate.

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

For the years ended December 31,	**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)%

The analysis of deferred income tax liabilities and deferred income tax assets is as follows:

As at December 31,	**2017**	2016
Deferred Income Tax Liabilities		
Deferred Tax Liabilities to be Settled Within 12 Months	**186**	6
Deferred Tax Liabilities to be Settled After More Than 12 Months	**6,229**	3,147
	6,415	3,153
Deferred Income Tax Assets		
Deferred Tax Assets to be Recovered Within 12 Months	**(374)**	(117)
Deferred Tax Assets to be Recovered After More Than 12 Months	**(428)**	(451)
	(802)	(568)
Net Deferred Income Tax Liability	**5,613**	2,585

The deferred income tax assets and liabilities to be settled within 12 months represents Management's estimate of the timing of the reversal of temporary differences and may not correlate to the current income tax expense of the subsequent year.

The movement in deferred income tax liabilities and assets, without taking into consideration the offsetting of balances within the same tax jurisdiction, is:

Deferred Income Tax Liabilities	PP&E	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2015	3,052	-	82	17	3,151
Charged (Credited) to Earnings	118	-	(76)	(16)	26
Charged (Credited) to OCI	(24)	-	-	-	(24)
As at December 31, 2016	3,146	-	6	1	3,153
Charged (Credited) to Earnings	625	164	11	1	801
Charged (Credited) to Purchase Price Allocation	2,506	-	-	-	2,506
Charged (Credited) to OCI	(45)	-	-	-	(45)
As at December 31, 2017	**6,232**	**164**	**17**	**2**	**6,415**

Deferred Income Tax Assets	Unused Tax Losses	Timing of Partnership Items	Risk Management	Other	Total
As at December 31, 2015	(172)	(36)	(8)	(119)	(335)
Charged (Credited) to Earnings	(102)	36	(77)	(92)	(235)
Charged (Credited) to OCI	4	-	-	(2)	2
As at December 31, 2016	(270)	-	(85)	(213)	(568)
Charged (Credited) to Earnings	67	-	(198)	(87)	(218)
Charged (Credited) to Share Capital	-	-	-	(28)	(28)
Charged (Credited) to OCI	12	-	-	-	12
As at December 31, 2017	**(191)**	**-**	**(283)**	**(328)**	**(802)**

Net Deferred Income Tax Liabilities	Total
Net Deferred Income Tax Liabilities as at December 31, 2015	2,816
Charged (Credited) to Earnings	(209)
Charged (Credited) to OCI	(22)
Net Deferred Income Tax Liabilities as at December 31, 2016	2,585
Charged (Credited) to Earnings	583
Charged (Credited) to Purchase Price Allocation	2,506
Charged (Credited) to Share Capital	(28)
Charged (Credited) to OCI	(33)
Net Deferred Income Tax Liabilities as at December 31, 2017	**5,613**

No deferred tax liability has been recognized as at December 31, 2017 on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future. In 2016, the Company had temporary differences of $7,457 million in respect of these investments where, on dissolution or sale, a tax liability might have existed. The Company has 100 percent control of that investment as of May 17, 2017.

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	2017	2016
Canada	**8,317**	4,273
United States	**1,714**	2,036
	10,031	6,309

As at December 31, 2017, the above tax pools included $73 million (2016 – $46 million) of Canadian non-capital losses and $593 million (2016 – $623 million) of U.S. federal net operating losses. These losses expire no earlier than 2025.

Also included in the December 31, 2017 tax pools are Canadian net capital losses totaling $8 million (2016 – $43 million), which are available for carry forward to reduce future capital gains. All of these net capital losses are unrecognized as a deferred income tax asset as at December 31, 2017 (2016 – $40 million). Recognition is dependent on future capital gains. The Company has not recognized $293 million (2016 – $730 million) of net capital losses associated with unrealized foreign exchange losses on its U.S. denominated debt.

13. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share — Basic and Diluted

For the years ended December 31,	**2017**	2016	2015
Earnings (Loss) From:			
Continuing Operations	**2,268**	(459)	914
Discontinued Operations	**1,098**	(86)	(296)
Net Earnings (Loss)	**3,366**	(545)	618
Weighted Average Number of Shares (millions)	**1,102.5**	833.3	818.7
Basic and Diluted Earnings (Loss) Per Share From: ($)			
Continuing Operations	**2.06**	(0.55)	1.11
Discontinued Operations	**0.99**	(0.10)	(0.36)
Net Earnings (Loss) Per Share	**3.05**	(0.65)	0.75

As at December 31, 2017, 43 million NSRs (2016 – 42 million) and 81 thousand TSARs (2016 – 3 million) were excluded from the diluted weighted average number of shares as their effect would have been anti-dilutive or their exercise prices exceed the market price of Cenovus's common shares. These instruments could potentially dilute earnings per share in the future. For further information on the Company's stock-based compensation plans, see Note 29.

B) Dividends Per Share

For the year ended December 31, 2017, the Company paid dividends of $225 million or $0.20 per share, all of which were paid in cash (2016 – $166 million or $0.20 per share, all of which were paid in cash; 2015 – $710 million or $0.8524 per share, including cash dividends of $528 million). The Cenovus Board of Directors declared a first quarter dividend of $0.05 per share, payable on March 29, 2018, to common shareholders of record as of March 15, 2018.

14. CASH AND CASH EQUIVALENTS

As at December 31,	**2017**	2016
Cash	**547**	542
Short-Term Investments	**63**	3,178
	610	3,720

15. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2017**	2016
Accruals	**1,379**	1,606
Prepaids and Deposits	**64**	127
Partner Advances	**94**	-
Note Receivable From Partner (1)	**-**	50
Trade	**193**	29
Joint Operations Receivables	**51**	11
Other	**49**	15
	1,830	1,838

(1) Note receivable from partner was interest bearing at a rate of 1.6783 percent per annum.

16. INVENTORIES

As at December 31,	**2017**	2016
Product		
Refining and Marketing	**894**	1,006
Oil Sands	**414**	156
Deep Basin	**2**	-
Conventional	**2**	20
Parts and Supplies	**77**	55
	1,389	1,237

During the year ended December 31, 2017, approximately $12,856 million of produced and purchased inventory was recorded as an expense (2016 – $9,964 million; 2015 – $10,618 million).

17. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2015	1,575
Additions	67
Transfers to PP&E (Note 18)	(49)
Exploration Expense (Note 10)	(2)
Change in Decommissioning Liabilities	(6)
As at December 31, 2016	1,585
Additions	147
Acquisition (Note 5) [(1)]	3,608
Transfers to Assets Held for Sale (Note 11)	(316)
Transfers to PP&E (Note 18)	(6)
Exploration Expense (Notes 10 and 11)	(890)
Change in Decommissioning Liabilities	5
Exchange Rate Movements and Other	19
Divestitures [(1)]	(479)
As at December 31, 2017	**3,673**

(1) In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3.

18. PROPERTY, PLANT AND EQUIPMENT, NET

	Upstream Assets				
	Development & Production	**Other Upstream**	**Refining Equipment**	**Other [1]**	**Total**
COST					
As at December 31, 2015	31,481	331	5,206	1,037	38,055
Additions	717	2	213	38	970
Transfers From E&E Assets (Note 17)	49	-	-	-	49
Change in Decommissioning Liabilities	(267)	-	(8)	-	(275)
Exchange Rate Movements and Other	(16)	-	(152)	(1)	(169)
Divestitures (Note 8)	(23)	-	-	-	(23)
As at December 31, 2016	31,941	333	5,259	1,074	38,607
Additions	1,324	-	168	89	1,581
Acquisition (Note 5) [2]	26,317	-	-	-	26,317
Transfers From E&E Assets (Note 17)	6	-	-	-	6
Transfers to Assets Held for Sale (Note 11)	(19,719)	-	-	-	(19,719)
Change in Decommissioning Liabilities	(67)	-	-	3	(64)
Exchange Rate Movements and Other	(28)	-	(364)	1	(391)
Divestitures (Note 8) [2]	(12,333)	-	(2)	-	(12,335)
As at December 31, 2017	**27,441**	**333**	**5,061**	**1,167**	**34,002**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2015	18,908	277	896	639	20,720
DD&A	1,173	31	205	66	1,475
Impairment Losses (Note 10)	481	-	-	4	485
Reversal of Impairment Losses (Note 10)	(462)	-	-	-	(462)
Exchange Rate Movements and Other	(4)	-	(25)	-	(29)
Divestitures (Note 8)	(8)	-	-	-	(8)
As at December 31, 2016	20,088	308	1,076	709	22,181
DD&A	1,653	23	209	68	1,953
Impairment Losses (Note 10)	77	-	-	-	77
Transfers to Assets Held for Sale (Note 11)	(16,120)	-	-	-	(16,120)
Exchange Rate Movements and Other	17	-	(91)	1	(73)
Divestitures (Note 8) [2]	(3,611)	-	(1)	-	(3,612)
As at December 31, 2017	**2,104**	**331**	**1,193**	**778**	**4,406**
CARRYING VALUE					
As at December 31, 2015	12,573	54	4,310	398	17,335
As at December 31, 2016	11,853	25	4,183	365	16,426
As at December 31, 2017	**25,337**	**2**	**3,868**	**389**	**29,596**

(1) *Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.*
(2) *In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and re-acquired it at fair value as required by IFRS 3. The carrying value of the pre-existing interest in FCCL was $8,602 million.*

PP&E includes the following amounts in respect of assets under construction and not subject to DD&A:

As at December 31,	**2017**	2016
Development and Production	**1,809**	537
Refining Equipment	**131**	206
	1,940	743

19. OTHER ASSETS

As at December 31,	**2017**	2016
Equity Investments	**37**	35
Long-Term Receivables	**11**	15
Prepaids	**9**	5
Other	**14**	1
	71	56

20. GOODWILL

As at December 31,	**2017**	2016
Carrying Value, Beginning of Year	**242**	242
Goodwill Recognized on Acquisition (Note 5)	**2,030**	-
Carrying Value, End of Year	**2,272**	242

The carrying amount of goodwill allocated to the Company's exploration and production CGUs is:

As at December 31,	**2017**	2016
Primrose (Foster Creek) [(1)]	**1,171**	242
Christina Lake [(1)]	**1,101**	-
	2,272	242

(1) Goodwill recognized on the Acquisition reflects measurement period adjustments.

For the purposes of impairment testing, goodwill is allocated to the CGU to which it relates. The assumptions used to test Cenovus's goodwill for impairment as at December 31, 2017 are consistent to those disclosed in Note 10.

21. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2017**	2016
Accruals	**2,006**	1,927
Trade	**337**	105
Interest	**86**	72
Partner Advances	**94**	-
Note Payable to Partner [(1)]	**-**	50
Employee Long-Term Incentives	**52**	42
Onerous Contract Provisions	**8**	18
Joint Operations Payables	**12**	-
Other	**40**	52
	2,635	2,266

(1) Note payable to partner was interest bearing at a rate of 1.6783 percent per annum.

22. CONTINGENT PAYMENT

As at January 1, 2017	**-**
Initial Recognition on May 17, 2017 (Note 5)	**361**
Re-measurement [(1)]	**(138)**
Liabilities Settled or Payable	**(17)**
As at December 31, 2017	**206**
Less: Current Portion	**38**
Long-Term Portion	**168**

(1) Contingent payment is carried at fair value. Changes in fair value are recorded in net earnings.

In connection with the Acquisition (see Note 5), Cenovus 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

$52.00 per barrel during the quarter. The quarterly payment will be $6 million for each dollar that the WCS price exceeds $52.00 per barrel. 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 at December 31, 2017, $17 million is payable under this agreement.

23. LONG-TERM DEBT

As at December 31,	Notes	US$ Principal Amount	2017	2016
Revolving Term Debt [(1)]	A	-	-	-
Asset Sale Bridge Credit Facility	B	-	-	-
U.S. Dollar Denominated Unsecured Notes	C	7,650	9,597	6,378
Total Debt Principal			9,597	6,378
Debt Discounts and Transaction Costs			(84)	(46)
Long-Term Debt			9,513	6,332

(1) *Revolving term debt may include Bankers' Acceptances, London Interbank Offered Rate based loans, prime rate loans and U.S. base rate loans.*

The weighted average interest rate on outstanding debt for the year ended December 31, 2017 was 4.9 percent (2016 – 5.3 percent).

A) Revolving Term Debt

On April 28, 2017, Cenovus amended its existing committed credit facility to increase the capacity of the facility 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 a $3.3 billion tranche maturing on November 30, 2021. Borrowings are available by way of Bankers' Acceptances, LIBOR based loans, prime rate loans or U.S. base rate loans. As at December 31, 2017, there were no amounts drawn on Cenovus's committed credit facility (2016 – $nil).

B) Asset Sale Bridge Credit Facility

In connection with the Acquisition, Cenovus borrowed $3.6 billion under a committed asset sale bridge credit facility. Net proceeds from the sale of the Company's Conventional segment assets (see Note 11) and cash on hand were used to repay and retire the committed asset bridge credit facility prior to December 31, 2017.

C) Unsecured Notes

Unsecured notes are composed of:

As at December 31,	US$ Principal Amount	2017	2016
5.70% due October 15, 2019	1,300	1,631	1,746
3.00% due August 15, 2022	500	627	671
3.80% due September 15, 2023	450	565	604
4.25% due April 15, 2027	1,200	1,505	-
5.25% due June 15, 2037	700	878	-
6.75% due November 15, 2039	1,400	1,756	1,880
4.45% due September 15, 2042	750	941	1,007
5.20% due September 15, 2043	350	439	470
5.40% due June 15, 2047	1,000	1,255	-
	7,650	9,597	6,378

In connection with the Acquisition, the Company 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, the Company completed an exchange offer ("Exchange Offering") whereby substantially all of the 2017 Notes were exchanged for notes registered under the Securities Act of 1933 with essentially the same terms and provisions as the 2017 Notes. The Exchange Offering has been treated as a modification for accounting purposes and not an extinguishment.

On October 10, 2017, Cenovus filed a base shelf prospectus that allows the Company 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. Following the completion of the Exchange Offering and as at December 31, 2017, US$4.6 billion was available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

As at December 31, 2017, the Company is in compliance with all of the terms of its debt agreements.

D) Mandatory Debt Payments

	US$ Principal Amount	**Total C$ Equivalent**
2018	-	**-**
2019	1,300	**1,631**
2020	-	**-**
2021	-	**-**
2022	500	**627**
Thereafter	5,850	**7,339**
	7,650	**9,597**

24. DECOMMISSIONING LIABILITIES

The decommissioning provision represents the present value of the expected future costs associated with the retirement of upstream crude oil and natural gas assets, refining facilities and the crude-by-rail terminal. The aggregate carrying amount of the obligation is:

	2017	2016
Decommissioning Liabilities, Beginning of Year	**1,847**	2,052
Liabilities Incurred	**20**	11
Liabilities Acquired (Note 5) [(1)]	**944**	-
Liabilities Settled	**(70)**	(51)
Liabilities Divested [(1)]	**(139)**	(1)
Transfers to Liabilities Related to Assets Held for Sale (Note 11)	**(1,621)**	-
Change in Estimated Future Cash Flows	**(155)**	(423)
Change in Discount Rate	**76**	131
Unwinding of Discount on Decommissioning Liabilities	**128**	130
Foreign Currency Translation	**(1)**	(2)
Decommissioning Liabilities, End of Year	**1,029**	1,847

(1) *In connection with the Acquisition, Cenovus was deemed to have disposed of its pre-existing interest in FCCL and reacquired it at fair value as required by IFRS.*

As at December 31, 2017, the undiscounted amount of estimated future cash flows required to settle the obligation is $3,360 million (2016 – $6,270 million), which has been discounted using a credit-adjusted risk-free rate of 5.3 percent (2016 – 5.9 percent). An inflation rate of two percent (2016 – two percent) was used to calculate the decommissioning provision. Most of these obligations are not expected to be paid for several years, or decades, and are expected to be funded from general resources at that time. The Company expects to settle approximately $40 million to $50 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from lower cost estimates.

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	2017		2016	
As at December 31,	**Credit-Adjusted Risk-Free Rate**	**Inflation Rate**	Credit-Adjusted Risk-Free Rate	Inflation Rate
One Percent Increase	**(98)**	**197**	(248)	327
One Percent Decrease	**192**	**(103)**	317	(259)

25. OTHER LIABILITIES

As at December 31,	2017	2016
Employee Long-Term Incentives	**43**	72
Pension and Other Post-Employment Benefit Plan (Note 26)	**62**	71
Onerous Contract Provisions	**37**	35
Other	**31**	33
	173	211

26. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides employees with a pension that includes either a defined contribution or defined benefit component and other post-employment benefit plan. Most of the employees participate in the defined contribution pension. Starting in 2012, employees who meet certain criteria may move from the current defined contribution component to a defined benefit component for their future service.

The defined benefit pension provides pension benefits at retirement based on years of service and final average earnings. Future enrollment is limited to eligible employees who meet certain criteria. The Company's OPEB provides certain retired employees with health care and dental benefits until age 65 and life insurance benefits.

The Company is required to file an actuarial valuation of its registered defined benefit pension with the provincial regulator at least every three years. The most recently filed valuation was dated December 31, 2014 and the next required actuarial valuation will be as at December 31, 2017.

A) Defined Benefit and OPEB Plan Obligation and Funded Status

Information related to defined benefit pension and OPEB plans, based on actuarial estimations, is:

	Pension Benefits		OPEB	
As at December 31,	2017	2016	2017	2016
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**173**	168	**23**	26
Current Service Costs	**14**	14	**2**	(3)
Interest Costs [1]	**7**	7	**1**	1
Benefits Paid	**(8)**	(25)	**(1)**	(1)
Plan Participant Contributions	**2**	2	**-**	-
Past Service Costs – Curtailments	**(6)**	-	**(1)**	-
Remeasurements:				
(Gains) Losses from Experience Adjustments	**1**	-	**-**	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	-	**(1)**	-
(Gains) Losses from Changes in Financial Assumptions	**(2)**	7	**(1)**	-
Defined Benefit Obligation, End of Year	**181**	173	**22**	23
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**125**	128	**-**	-
Employer Contributions	**9**	14	**-**	-
Plan Participant Contributions	**2**	2	**-**	-
Benefits Paid	**(8)**	(25)	**-**	-
Interest Income [1]	**4**	3	**-**	-
Remeasurements:				
Return on Plan Assets (Excluding Interest Income)	**9**	3	**-**	-
Fair Value of Plan Assets, End of Year	**141**	125	**-**	-
Pension and OPEB (Liability) [2]	**(40)**	(48)	**(22)**	(23)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Pension and OPEB liabilities are included in other liabilities on the Consolidated Balance Sheets.

In connection with the divestitures of the Company's legacy Conventional assets, affected employees left the plans resulting in a curtailment gain.

The weighted average duration of the defined benefit pension and OPEB obligations are 16 years and 10 years, respectively.

B) Pension and OPEB Costs

	Pension Benefits			OPEB		
For the years ended December 31,	**2017**	2016	2015	**2017**	2016	2015
Defined Benefit Plan Cost						
Current Service Costs	**14**	14	19	**2**	(3)	3
Past Service Costs – Curtailments	**(6)**	-	(5)	**(1)**	-	-
Net Settlement Costs	**-**	-	3	**-**	-	-
Net Interest Costs	**3**	4	6	**1**	1	1
Remeasurements:						
Return on Plan Assets (Excluding Interest Income)	**(9)**	(3)	3	**-**	-	-
(Gains) Losses from Experience Adjustments	**1**	-	(3)	**-**	-	-
(Gains) Losses from Changes in Demographic Assumptions	**-**	-	-	**(1)**	-	-
(Gains) Losses from Changes in Financial Assumptions	**(2)**	7	(28)	**(1)**	-	-
Defined Benefit Plan Cost (Recovery)	**1**	22	(5)	**-**	(2)	4
Defined Contribution Plan Cost	**27**	25	29	**-**	-	-
Total Plan Cost	**28**	47	24	**-**	(2)	4

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark comprised of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints which reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored quarterly and is re-balanced as necessary. The asset allocation structure targets an investment of 50 to 75 percent in equity securities, 25 to 35 percent in fixed income assets, zero to 15 percent in real estate assets and zero to 10 percent in cash and cash equivalents.

The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the plan assets is:

As at December 31,	**2017**	2016
Equity Funds	**89**	73
Bond Funds	**29**	25
Non-Invested Assets	**11**	13
Real Estate Funds	**9**	9
Cash and Cash Equivalents	**3**	5
	141	125

Fair value of equities and bonds are based on the trading price of the underlying funds. The fair value of the non-invested assets is the discounted value of the expected future payments. The fair value of the real estate funds reflects the market value and the fund manager's appraisal value of the assets.

Equity funds do not include any direct investments in Cenovus shares.

D) Funding

The defined benefit pension is funded in accordance with federal and provincial government pension legislation, where applicable. Contributions are made to trust funds administered by an independent trustee. The Company's contributions to the defined benefit pension plan are based on the most recent actuarial valuation as at December 31, 2014, and direction of the Management Pension Committee and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. The expected employer contributions for the year ended December 31, 2018 are $9 million for the defined benefit pension plan and $nil for the OPEB. The OPEB is funded on an as required basis.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations and expenses are as follows:

	Pension Benefits			**OPEB**		
For the years ended December 31,	**2017**	2016	2015	**2017**	2016	2015
Discount Rate	**3.50%**	3.75%	4.00%	**3.25%**	3.75%	3.75%
Future Salary Growth Rate	**3.81%**	3.80%	3.80%	**5.08%**	5.15%	5.15%
Average Longevity (years)	**88.0**	87.9	88.3	**88.0**	87.9	88.3
Health Care Cost Trend Rate	**N/A**	N/A	N/A	**6.00%**	7.00%	7.00%

The discount rates are determined with reference to market yields on high quality corporate debt instruments of similar duration to the benefit obligations at the end of the reporting period.

Sensitivities

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumptions is:

	2017		2016	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
One Percent Change:				
Discount Rate	**(28)**	**36**	(25)	32
Future Salary Growth Rate	**3**	**(3)**	3	(3)
Health Care Cost Trend Rate	**1**	**(1)**	2	(1)
One Year Change in Assumed Life Expectancy	**4**	**(4)**	4	(4)

The above sensitivity analysis is based on a change in an assumption while holding all other assumptions constant; however, the changes in some assumptions may be correlated. The same methodologies have been used to calculate the sensitivity of the defined benefit obligation to significant actuarial assumptions as have been applied when calculating the defined benefit pension liability recorded on the Consolidated Balance Sheets.

F) Risks

Through its defined benefit pension and OPEB plans, the Company is exposed to actuarial risks, such as longevity risk, interest rate risk, investment risk and salary risk.

Longevity Risk

The present value of the defined benefit plan obligation is calculated by reference to the best estimate of the mortality of plan participants both during and after their employment. An increase in the life expectancy of participants will increase the defined benefit plan obligation.

Interest Rate Risk

A decrease in corporate bond yields will increase the defined benefit plan obligation, although this will be partially offset by an increase in the return on debt holdings.

Investment Risk

The present value of the defined benefit plan obligation is calculated using a discount rate determined by reference to high quality corporate bond yields. If the return on plan assets is below this rate, a plan deficit will result. Due to the long-term nature of the plan liabilities, a higher portion of the plan assets are invested in equity securities than in debt instruments and real estate.

Salary Risk

The present value of the defined benefit plan obligation is calculated by reference to the future salaries of plan participants. As such, an increase in the salary of the plan participants will increase the defined benefit obligation.

27. SHARE CAPITAL

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Company's Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding

	2017		2016	
As at December 31,	**Number of Common Shares** (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**833,290**	**5,534**	833,290	5,534
Common Shares Issued, Net of Issuance Costs and Tax	**187,500**	**2,927**	-	-
Common Shares Issued to ConocoPhillips (Note 5)	**208,000**	**2,579**	-	-
Outstanding, End of Year	**1,228,790**	**11,040**	833,290	5,534

In connection with the Acquisition (see Note 5), 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, the Company issued 208 million common shares to ConocoPhillips on May 17, 2017 as partial consideration for the Acquisition. In relation to the share consideration, Cenovus and ConocoPhillips entered into an investor agreement, and a registration rights agreement which, among other things, restricted ConocoPhillips from selling or hedging its Cenovus common shares until after November 17, 2017. ConocoPhillips is also restricted from nominating new members to Cenovus's Board of Directors and must vote its Cenovus common shares in accordance with Management's recommendations or abstain from voting until such time ConocoPhillips owns 3.5 percent or less of the then outstanding common shares of Cenovus. As at December 31, 2017, ConocoPhillips continued to hold these common shares.

There were no preferred shares outstanding as at December 31, 2017 (2016 – nil).

As at December 31, 2017, there were 15 million (2016 – 12 million) common shares available for future issuance under the stock option plan.

C) Paid in Surplus

Cenovus's paid in surplus reflects the Company's retained earnings prior to the split of Encana Corporation ("Encana") under the plan of arrangement into two independent energy companies, Encana and Cenovus (pre-arrangement earnings). In addition, paid in surplus includes stock-based compensation expense related to the Company's NSRs discussed in Note 29A.

	Pre-Arrangement Earnings	**Stock-Based Compensation**	**Total**
As at December 31, 2015	4,086	244	4,330
Stock-Based Compensation Expense	-	20	20
As at December 31, 2016	4,086	264	4,350
Stock-Based Compensation Expense	-	11	11
As at December 31, 2017	**4,086**	**275**	**4,361**

28. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Pension Plan	Foreign Currency Translation Adjustment	Available for Sale Financial Assets	Total
As at December 31, 2015	(10)	1,014	16	1,020
Other Comprehensive Income (Loss), Before Tax	(4)	(106)	(4)	(114)
Income Tax	1	-	3	4
As at December 31, 2016	**(13)**	**908**	**15**	**910**
Other Comprehensive Income (Loss), Before Tax	**12**	**(275)**	**(1)**	**(264)**
Income Tax	**(3)**	**-**	**-**	**(3)**
As at December 31, 2017	**(4)**	**633**	**14**	**643**

29. STOCK-BASED COMPENSATION PLANS

A) Employee Stock Option Plan

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market price for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company on or after February 24, 2011 have associated NSRs. The NSRs, in lieu of exercising the option, give the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

Options issued by the Company under the Employee Stock Option Plan prior to February 24, 2011 have associated TSARs. In lieu of exercising the options, the TSARs give the option holder the right to receive a cash payment equal to the excess of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option.

The TSARs and NSRs vest and expire under the same terms and conditions as the underlying options.

NSRs

The weighted average unit fair value of NSRs granted during the year ended December 31, 2017 was $3.10 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.00%**
Expected Dividend Yield	**1.13%**
Expected Volatility [1]	**29.14%**
Expected Life (years)	**3.70**

(1) *Expected volatility has been based on historical share volatility of the Company and comparable industry peers.*

The following tables summarize information related to the NSRs:

As at December 31, 2017	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**41,644**	**30.57**
Granted	**3,537**	**14.81**
Exercised	**-**	**-**
Forfeited	**(2,454)**	**28.27**
Outstanding, End of Year	**42,727**	**29.40**

As at December 31, 2017	**Outstanding NSRs**			**Exercisable NSRs**	
Range of Exercise Price ($)	**Number of NSRs** (thousands)	**Weighted Average Remaining Contractual Life** (years)	**Weighted Average Exercise Price** ($)	**Number of NSRs** (thousands)	**Weighted Average Exercise Price** ($)
10.00 to 14.99	**3,319**	**5.4**	**14.80**	**-**	**-**
15.00 to 19.99	**3,313**	**5.2**	**19.51**	**995**	**19.51**
20.00 to 24.99	**3,723**	**4.1**	**22.25**	**2,254**	**22.26**
25.00 to 29.99	**12,115**	**3.1**	**28.38**	**12,106**	**28.39**
30.00 to 34.99	**10,419**	**2.2**	**32.64**	**10,419**	**32.64**
35.00 to 39.99	**9,838**	**0.8**	**38.19**	**9,838**	**38.19**
	42,727	**2.8**	**29.40**	**35,612**	**31.70**

TSARs

The Company had a liability of $nil as at December 31, 2017 (2016 – $nil) in the Consolidated Balance Sheets based on the fair value of each TSAR held by Cenovus employees. Fair value was estimated at the period-end date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate	**1.85%**
Expected Dividend Yield	**1.51%**
Expected Volatility [(1)]	**28.89%**
Cenovus's Common Share Price ($)	**11.48**

(1) Expected volatility has been based on historical share volatility of the Company and comparable industry peers.

The intrinsic value of vested TSARs held by Cenovus employees as at December 31, 2017 was $nil (2016 – $nil).

The following table summarizes information related to the TSARs held by Cenovus employees:

As at December 31, 2017	**Number of TSARs** (thousands)	**Weighted Average Exercise Price** ($)
Outstanding, Beginning of Year	**3,373**	**26.66**
Exercised for Cash Payment	**-**	**-**
Exercised as Options for Common Shares	**-**	**-**
Forfeited	**(16)**	**29.19**
Expired	**(3,276)**	**26.48**
Outstanding, End of Year	**81**	**33.52**

The market price of Cenovus's common shares on the TSX as at December 31, 2017 was $11.48.

B) Performance Share Units

Cenovus has granted PSUs to certain employees under its Performance Share Unit Plan for Employees. PSUs are whole share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. For a portion of PSUs, the number of PSUs eligible for payment is determined over three years based on the units granted multiplied by 30 percent after year one, 30 percent after year two and 40 percent after year three. All PSUs are eligible to vest based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $37 million as at December 31, 2017 (2016 – $51 million) in the Consolidated Balance Sheets for PSUs based on the market value of Cenovus's common shares at the end of the year. As PSUs are paid out upon vesting, the intrinsic value of vested PSUs was $nil as at December 31, 2017 and 2016.

The following table summarizes the information related to the PSUs held by Cenovus employees:

As at December 31, 2017	**Number of PSUs** (thousands)
Outstanding, Beginning of Year	**6,157**
Granted	**2,392**
Vested and Paid Out	**(451)**
Cancelled	**(1,192)**
Units in Lieu of Dividends	**112**
Outstanding, End of Year	**7,018**

C) Restricted Share Units

Cenovus has granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole-share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs vest after three years.

RSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation costs over the vesting period. Fluctuations in the fair value are recognized as stock-based compensation costs in the period they occur.

The Company has recorded a liability of $41 million as at December 31, 2017 (2016 – $30 million) in the Consolidated Balance Sheets for RSUs based on the market value of Cenovus's common shares at the end of the year. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2017 and 2016.

The following table summarizes the information related to the RSUs held by Cenovus employees:

As at December 31, 2017	**Number of RSUs** (thousands)
Outstanding, Beginning of Year	**3,790**
Granted	**3,278**
Vested and Paid Out	**(101)**
Cancelled	**(282)**
Units in Lieu of Dividends	**100**
Outstanding, End of Year	**6,785**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible employees have the option to convert either zero, 25 or 50 percent of their annual bonus award into DSUs. DSUs vest immediately, are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company has recorded a liability of $17 million as at December 31, 2017 (2016 – $32 million) in the Consolidated Balance Sheets for DSUs based on the market value of Cenovus's common shares at the end of the year. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

The following table summarizes the information related to the DSUs held by Cenovus directors, officers and employees:

As at December 31, 2017	**Number of DSUs** (thousands)
Outstanding, Beginning of Year	**1,598**
Granted to Directors	**136**
Granted	**93**
Units in Lieu of Dividends	**27**
Redeemed	**(414)**
Outstanding, End of Year	**1,440**

E) Total Stock-Based Compensation

For the years ended December 31,	**2017**	2016	2015
NSRs	**9**	15	27
TSARs	**-**	(1)	(5)
PSUs	**(7)**	13	(13)
RSUs	**3**	13	6
DSUs	**(11)**	7	(5)
Stock-Based Compensation Expense (Recovery)	**(6)**	47	10
Stock-Based Compensation Costs Capitalized	**3**	12	6
Total Stock-Based Compensation	**(3)**	59	16

30. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2017**	2016	2015
Salaries, Bonuses and Other Short-Term Employee Benefits	**606**	500	534
Defined Contribution Pension Plan	**19**	16	19
Defined Benefit Pension Plan and OPEB	**8**	11	17
Stock-Based Compensation Expense (Note 29)	**(6)**	47	10
Termination Benefits	**19**	19	43
	646	593	623

31. RELATED PARTY TRANSACTIONS

Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	**2017**	2016	2015
Salaries, Director Fees and Short-Term Benefits	**26**	27	30
Post-Employment Benefits	**4**	4	5
Stock-Based Compensation	**6**	4	5
	36	35	40

Post employment benefits represent the present value of future pension benefits earned during the year. Stock-based compensation includes the costs recorded during the year associated with stock options, NSRs, TSARs, PSUs, RSUs and DSUs.

32. CAPITAL STRUCTURE

Cenovus's capital structure objectives remain unchanged from previous periods. Cenovus's capital structure consists of shareholders' equity plus Net Debt. Net Debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents. Cenovus conducts its business and makes decisions consistent with that of an investment grade company. The Company's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions while maintaining the ability to meet the Company's financial obligations as they come due.

Cenovus monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of Net Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA") and Net Debt to Capitalization. These metrics are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

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

A) 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 Expense (Recovery)	**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 Divestitures 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 twelve-month basis. Includes discontinued operations.

B) Net Debt to Capitalization

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

As at December 31, 2017, Cenovus's Net Debt to Adjusted EBITDA is 2.8 times, which is above the Company's target. However, it is important to note that Adjusted EBITDA is calculated on a rolling twelve 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.

Cenovus's objective is to maintain a high level of capital discipline and manage its capital structure to help ensure sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, draw down on its credit facility or repay existing debt, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new debt, or issue new shares.

Cenovus has in place a committed credit facility that consists of a $1.2 billion tranche maturing on November 30, 2020 and a $3.3 billion tranche maturing on November 30, 2021. As at December 31, 2017, no amounts were drawn on its committed credit facility. Under the committed credit facility, the Company is required to maintain a debt to capitalization ratio, as defined in the agreement, not to exceed 65 percent. The Company is well below this limit.

In addition, the Company has in place a base shelf prospectus which expires in November 2019. As at December 31, 2017, US$4.6 billion remains available under the base shelf prospectus. Offerings under the base shelf prospectus are subject to market conditions.

As at December 31, 2017, Cenovus is in compliance with all of the terms of its debt agreements.

33. FINANCIAL INSTRUMENTS

Cenovus's financial assets and financial liabilities consist of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, risk management assets and liabilities, available for sale financial assets, long-term receivables, contingent payment, short-term borrowings and long-term debt. Risk management assets and liabilities arise from the use of derivative financial instruments.

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of long-term receivables approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair values of long-term borrowings have been determined based on period-end trading prices of long-term borrowings on the secondary market (Level 2). As at December 31, 2017, the carrying value of Cenovus's debt was $9,513 million and the fair value was $10,061 million (2016 carrying value – $6,332 million; fair value – $6,539 million).

Available for sale financial assets comprise private equity investments. These assets are carried at fair value on the Consolidated Balance Sheets in other assets. Fair value is determined based on recent private placement transactions (Level 3) when available. The following table provides a reconciliation of changes in the fair value of available for sale financial assets:

As at December 31,	**2017**	2016
Fair Value, Beginning of Year	**35**	42
Net Acquisition of Investments	**3**	-
Change in Fair Value [1]	**(1)**	(4)
Impairment Losses [2]	**-**	(3)
Fair Value, End of Year	**37**	35

(1) Changes in fair value on available for sale financial assets are recorded in OCI.
(2) Impairment losses on available for sale financial assets are reclassified from OCI to profit or loss.

B) Fair Value of Risk Management Assets and Liabilities

The Company's risk management assets and liabilities consist of crude oil swaps and options, as well as condensate and interest rate swaps. Crude oil, condensate and, if entered, natural gas contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity extrapolated to the end of the term of the contract (Level 2). The fair value of interest rate swaps are calculated using external valuation models which incorporate observable market data, including interest rate yield curves (Level 2).

Summary of Unrealized Risk Management Positions

	2017			2016		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Crude Oil	**63**	**1,031**	**(968)**	21	307	(286)
Interest Rate	**2**	**20**	**(18)**	3	8	(5)
Total Fair Value	**65**	**1,051**	**(986)**	24	315	(291)

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	**2017**	2016
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(986)**	(291)

Prices sourced from observable data or market corroboration refers to the fair value of contracts valued in part using active quotes and in part using observable, market-corroborated data.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities:

As at December 31,	2017	2016
Fair Value of Contracts, Beginning of Year	**(291)**	271
Fair Value of Contracts Realized During the Year [(1)]	**200**	(211)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year	**(929)**	(343)
Unamortized Premium on Put Options	**16**	-
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**18**	(8)
Fair Value of Contracts, End of Year	**(986)**	(291)

(1) *Includes a realized loss of $33 million (2016 – $58 million gain) related to the Conventional segment which is included in discontinued operations.*

Financial assets and liabilities are offset only if Cenovus has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. Cenovus offsets risk management assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. No additional unrealized risk management positions are subject to an enforceable master netting arrangement or similar agreement that are not otherwise offset.

The following table provides a summary of the Company's offsetting risk management positions:

	2017			2016		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**135**	**1,121**	**(986)**	75	366	(291)
Amount Offset	**(70)**	**(70)**	**-**	(51)	(51)	-
Net Amount per Consolidated Financial Statements	**65**	**1,051**	**(986)**	24	315	(291)

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. Additional cash collateral is required if, on a net basis, risk management payables exceed risk management receivables on a particular day. As at December 31, 2017, $26 million (2016 – $84 million) was pledged as collateral, of which $nil (2016 – $18 million) could have been withdrawn.

C) Fair Value of Contingent Payment

The contingent payment is carried at fair value on the Consolidated Balance Sheets. Fair value is estimated by calculating the present value of the future expected cash flows using an option pricing model (Level 3), which assumes the probability distribution for WCS is based on the volatility of WTI options, volatility of Canadian-U.S. foreign exchange rate options and WCS futures pricing, and discounted at a credit-adjusted risk-free rate of 3.3 percent. Fair value of the contingent payment has been calculated by Cenovus's internal valuation team which consists of individuals who are knowledgeable and have experience in fair value techniques. As at December 31, 2017, the fair value of the contingent payment was estimated to be $206 million.

As at December 31, 2017, average WCS forward pricing for the remaining term of the contingent payment is US$35.51 per barrel or C$44.55 per barrel. The average volatility of WTI options and the Canadian-U.S. foreign exchange rates used to value the contingent payment was 20 percent and seven percent, respectively. Changes in the following inputs to the option pricing model, with fluctuations in all other variables held constant, could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

	Sensitivity Range	**Increase**	**Decrease**
WCS Forward Prices	± $5.00 per bbl	**(167)**	**111**
WTI Option Volatility	± five percent	**(95)**	**85**
U.S. to Canadian Dollar Foreign Exchange Rate Volatility	± five percent	**2**	**(27)**

D) Earnings Impact of (Gains) Losses From Risk Management Positions

For the years ended December 31,	**2017**	2016	2015
Realized (Gain) Loss [(1)]	**167**	(153)	(447)
Unrealized (Gain) Loss [(2)]	**729**	554	195
(Gain) Loss on Risk Management From Continuing Operations	**896**	401	(252)

(1) *Realized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates. Excludes realized risk management losses of $33 million in 2017 (2016 – $58 million gain; 2015 – $209 million gain) that were classified as discontinued operations.*
(2) *Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.*

34. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates as well as credit risk and liquidity risk. To manage exposure to interest rate volatility, the Company entered into interest rate swap contracts related to expected future debt issuances. As at December 31, 2017, Cenovus had a notional amount of US$400 million in interest rate swaps. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts. No foreign exchange contracts were outstanding at December 31, 2017.

Net Fair Value of Risk Management Positions

As at December 31, 2017	**Notional Volumes**	**Terms**	**Average Price**	**Fair Value Asset (Liability)**
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	60,000 bbls/d	January – June 2018	US$53.34/bbl	**(172)**
WTI Fixed Price	150,000 bbls/d	January – June 2018	US$48.91/bbl	**(384)**
WTI Fixed Price	75,000 bbls/d	July – December 2018	US$49.32/bbl	**(158)**
Brent Put Options	25,000 bbls/d	January – June 2018	US$53.00/bbl	**1**
Brent Collars	80,000 bbls/d	January – June 2018	US$49.54 – US$59.86/bbl	**(124)**
Brent Collars	75,000 bbls/d	July – December 2018	US$49.00 – US$59.69/bbl	**(110)**
WTI Collars	10,000 bbls/d	January – June 2018	US$45.30 – US$62.77/bbl	**(2)**
WCS Differential	16,300 bbls/d	January – March 2018	US$(13.11)/bbl	**14**
WCS Differential	14,800 bbls/d	April – June 2018	US$(14.05)/bbl	**7**
WCS Differential	10,500 bbls/d	January – December 2018	US$(14.52)/bbl	**25**
Other Financial Positions [(1)]				**(65)**
Crude Oil Fair Value Position				**(968)**
Interest Rate Swaps				**(18)**
Total Fair Value				**(986)**

(1) *Other financial positions are part of ongoing operations to market the Company's production.*

A) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. The Company's policy does not allow the use of derivative instruments for speculative purposes.

Crude Oil – The Company has used fixed price swaps, put options and costless collars to partially mitigate its exposure to the commodity price risk on its crude oil sales. In addition, Cenovus has entered into a number of transactions to help protect against widening light/heavy crude oil price differentials.

Condensate – The Company has used fixed price swaps to partially mitigate its exposure to the commodity price risk on its condensate purchases.

Natural Gas – The Company may enter into transactions to partially mitigate its natural gas commodity price risk. To help protect against widening natural gas price differentials in various production areas, Cenovus may also enter into transactions to manage the price differentials between production areas and various sales points.

Sensitivities

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices, with all other variables held constant. Management believes the fluctuations identified in the table below are a reasonable measure of volatility. The impact of fluctuating commodity prices and interest rates on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

As at December 31, 2017	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)**

As at December 31, 2016	Sensitivity Range	Increase	Decrease
Crude Oil Commodity Price	± US$5.00 per bbl Applied to Brent, WTI and Condensate Hedges	(198)	193
Crude Oil Differential Price	± US$2.50 per bbl Applied to Differential Hedges Tied to Production	1	(1)

B) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

As disclosed in Note 7, Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada. As at December 31, 2017, Cenovus had US$7,650 million in U.S. dollar debt issued from Canada (2016 – US$4,750 million). In respect of these financial instruments, the impact of changes in the U.S. to Canadian dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

For the years ended December 31,	2017	2016
$0.01 Increase in the U.S. to Canadian Dollar Foreign Exchange Rate	**77**	48
$0.01 Decrease in the U.S. to Canadian Dollar Foreign Exchange Rate	**(77)**	(48)

C) Interest Rate Risk

Interest rate risk arises from changes in market interest rates that may affect earnings, cash flows and valuations. Cenovus has the flexibility to partially mitigate its exposure to interest rate changes by maintaining a mix of both fixed and floating rate debt. In addition, to manage exposure to interest rate volatility, the Company entered into interest rate swap contracts. As at December 31, 2017, Cenovus had a notional amount of US$400 million (2016 – US$400 million) in interest rate swaps. In respect of these financial instruments, the impact of changes in the interest rate would have resulted in a change to unrealized gains (losses) impacting earnings before income tax as follows:

For the years ended December 31,	2017	2016
50 Basis Points Increase	**44**	45
50 Basis Points Decrease	**(50)**	(52)

As at December 31, 2017, the increase or decrease in net earnings for a one percent change in interest rates on floating rate debt amounts to $nil (2016 – $nil; 2015 – $nil). This assumes the amount of fixed and floating debt remains unchanged from the respective balance sheet dates.

D) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee of the Board of Directors designed to ensure that its credit exposures are within an acceptable risk level as determined by the Company's Enterprise Risk Management Policy. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Cenovus's exposure to its counterparties is within credit policy tolerances.

As at December 31, 2017 and 2016, substantially all of the Company's accounts receivable were less than 60 days. As at December 31, 2017, 89 percent (2016 – 90 percent) of Cenovus's accounts receivable and financial derivative credit exposures are with investment grade counterparties. As at December 31, 2017, Cenovus had three counterparties (2016 – three counterparties) whose net settlement position individually accounted for more than 10 percent of the fair value of the outstanding in-the-money net financial and physical contracts. The maximum credit risk exposure associated with accounts receivable and accrued revenues, risk management assets, and long-term receivables is the total carrying value.

E) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price. Cenovus manages its liquidity risk through the active management of cash and debt and by maintaining appropriate access to credit, which may be impacted by the Company's credit ratings. As disclosed in Note 32, over the long term, Cenovus targets a Net Debt to Adjusted EBITDA of less than 2.0 times to manage the Company's overall debt position.

Cenovus manages its liquidity risk by ensuring that it has access to multiple sources of capital including: cash and cash equivalents, cash from operating activities, undrawn credit facility capacity and availability under its shelf prospectus. As at December 31, 2017, Cenovus had $610 million in cash and cash equivalents, and $4.5 billion available on its committed credit facility. In addition, Cenovus has unused capacity of US$4.6 billion under a base shelf prospectus, the availability of which is dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2017	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	2,635	-	-	-	**2,635**
Risk Management Liabilities [1]	1,031	20	-	-	**1,051**
Long-Term Debt [2]	494	2,527	1,429	13,309	**17,759**
Other	-	21	11	16	**48**

As at December 31, 2016	Less than 1 Year	Years 2 and 3	Years 4 and 5	Thereafter	Total
Accounts Payable and Accrued Liabilities	2,266	-	-	-	2,266
Risk Management Liabilities [1]	293	22	-	-	315
Long-Term Debt [2]	339	2,662	1,150	7,550	11,701
Other	-	25	8	16	49

(1) *Risk management liabilities subject to master netting agreements.*
(2) *Principal and interest, including current portion.*

35. SUPPLEMENTARY CASH FLOW INFORMATION

For the years ended December 31,	**2017**	2016	2015
Interest Paid	**538**	350	330
Interest Received	**31**	32	19
Income Taxes Paid	**12**	11	933

The following table provides a reconciliation of cash flows arising from financing activities:

	Dividends Payable	Current Portion of Long-Term Debt	Long-Term Debt	Share Capital
As at December 31, 2015	-	-	6,525	5,534
Changes From Financing Cash Flows:				
Dividends Paid	(166)	-	-	-
Non-Cash Changes:				
Dividends Declared	166	-	-	-
Unrealized Foreign Exchange (Gain) Loss (Note 7)	-	-	(196)	-
Amortization of Debt Discounts	-	-	3	-
As at December 31, 2016	**-**	**-**	**6,332**	**5,534**
Changes From Financing Cash Flows:				
Issuance of Long-Term Debt	**-**	**-**	**3,842**	**-**
Net Issuance (Repayment) of Revolving Long-Term Debt	**-**	**-**	**32**	**-**
Issuance of Debt Under Asset Sale Bridge Facility	**-**	**892**	**2,677**	**-**
(Repayment) of Debt Under Asset Sale Bridge Facility	**-**	**(900)**	**(2,700)**	**-**
Common Shares Issued, Net of Issuance Costs	**-**	**-**	**-**	**2,899**
Dividends Paid	**(225)**	**-**	**-**	**-**
Non-Cash Changes:				
Common Shares Issued to ConocoPhillips	**-**	**-**	**-**	**2,579**
Deferred Taxes on Share Issuance Costs	**-**	**-**	**-**	**28**
Dividends Declared	**225**	**-**	**-**	**-**
Unrealized Foreign Exchange (Gain) Loss	**-**	**-**	**(697)**	**-**
Finance Costs	**-**	**8**	**28**	**-**
Other	**-**	**-**	**(1)**	**-**
As at December 31, 2017	**-**	**-**	**9,513**	**11,040**

36. COMMITMENTS AND CONTINGENCIES

A) Commitments

Future payments for the Company's commitments are below. A commitment is an enforceable and legally binding agreement to make a payment in the future for the purchase of goods and services. These items exclude amounts recorded in the Consolidated Balance Sheets.

As at December 31, 2017	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Transportation and Storage [1]	899	886	919	1,123	1,223	13,260	**18,310**
Operating Leases (Building Leases) [2]	155	146	142	141	140	2,305	**3,029**
Capital Commitments	16	2	-	-	-	-	**18**
Other Long-Term Commitments	109	39	32	28	25	122	**355**
Total Payments [3]	1,179	1,073	1,093	1,292	1,388	15,687	**21,712**
Fixed Price Product Sales	-	-	-	-	-	-	**-**

As at December 31, 2016	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	Total
Transportation and Storage [1]	682	711	722	1,031	1,239	21,875	26,260
Operating Leases (Building Leases) [2]	101	146	146	145	142	2,465	3,145
Product Purchases	70	-	-	-	-	-	70
Capital Commitments	23	3	-	-	-	-	26
Other Long-Term Commitments	80	27	26	15	15	108	271
Total Payments [3]	956	887	894	1,191	1,396	24,448	29,772
Fixed Price Product Sales	3	-	-	-	-	-	3

(1) Includes transportation commitments of $9 billion (2016 – $19 billion) that are subject to regulatory approval or have been approved, but are not yet in service.
(2) Excludes committed payment for which a provision has been provided.
(3) For 2017, contracts undertaken on behalf of WRB are reflected at Cenovus's 50 percent interest. For 2016, contracts undertaken on behalf of FCCL and WRB are reflected at Cenovus's 50 percent interest.

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.

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

In addition to the above, Cenovus's commitments related to its risk management program are disclosed in Note 34.

B) Contingencies

Legal Proceedings

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

Decommissioning Liabilities

Cenovus is responsible for the retirement of long-lived assets at the end of their useful lives. Cenovus has recorded a liability of $1,029 million, based on current legislation and estimated costs, related to its upstream properties, refining facilities and midstream facilities. Actual costs may differ from those estimated due to changes in legislation and changes in costs.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

Contingent Payment

In connection with the Acquisition, Cenovus 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 $52.00 per barrel during the quarter. As at December 31, 2017, the estimated fair value of the contingent payment was $206 million (see Note 22).