Cenovus Energy Inc.

Interim Consolidated Financial Statements (unaudited)

For the Period Ended December 31, 2016

(Canadian Dollars)

CONSOLIDATED FINANCIAL STATEMENTS (unaudited)

For the period ended December 31, 2016

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CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) (unaudited)

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

	Notes	Three Months Ended 2016	Three Months Ended 2015	Twelve Months Ended 2016	Twelve Months Ended 2015
Revenues	1				
Gross Sales		**3,695**	2,955	**12,282**	13,207
Less: Royalties		**53**	31	**148**	143
		3,642	2,924	**12,134**	13,064
Expenses	1				
Purchased Product		**2,075**	1,808	**6,978**	7,374
Transportation and Blending		**541**	534	**1,901**	2,043
Operating		**439**	460	**1,683**	1,839
Production and Mineral Taxes		**3**	2	**12**	18
(Gain) Loss on Risk Management	19	**102**	(213)	**343**	(461)
Depreciation, Depletion and Amortization	7,11	**(71)**	659	**1,498**	2,114
Exploration Expense	7,10	**-**	117	**2**	138
General and Administrative		**101**	109	**326**	335
Finance Costs	3	**124**	123	**492**	482
Interest Income		**(7)**	(8)	**(52)**	(28)
Foreign Exchange (Gain) Loss, Net	4	**140**	204	**(198)**	1,036
Research Costs		**6**	7	**36**	27
(Gain) Loss on Divestiture of Assets	5	**-**	3	**6**	(2,392)
Other (Income) Loss, Net	6	**27**	1	**34**	2
Earnings (Loss) Before Income Tax		**162**	(882)	**(927)**	537
Income Tax Expense (Recovery)	8	**71**	(241)	**(382)**	(81)
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Net Earnings (Loss) Per Share ($)	9				
Basic and Diluted		**0.11**	(0.77)	**(0.65)**	0.75

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (unaudited)

For the periods ended December 31,
($ millions)

	Notes	Three Months Ended 2016	Three Months Ended 2015	Twelve Months Ended 2016	Twelve Months Ended 2015
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Other Comprehensive Income (Loss), Net of Tax	16				
Items That Will Not be Reclassified to Profit or Loss:					
Actuarial Gain (Loss) Relating to Pension and Other Post-Retirement Benefits		**6**	15	**(3)**	20
Items That May be Reclassified to Profit or Loss:					
Available for Sale Financial Assets – Change in Fair Value		**-**	6	**(2)**	6
Available for Sale Financial Assets – Reclassified to Profit or Loss		**-**	-	**1**	-
Foreign Currency Translation Adjustment		**99**	124	**(106)**	587
Total Other Comprehensive Income (Loss), Net of Tax		**105**	145	**(110)**	613
Comprehensive Income (Loss)		**196**	(496)	**(655)**	1,231

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED BALANCE SHEETS (unaudited)

As at December 31,
($ millions)

	Notes	2016	2015
Assets			
Current Assets			
Cash and Cash Equivalents		**3,720**	4,105
Accounts Receivable and Accrued Revenues		**1,838**	1,251
Income Tax Receivable		**6**	6
Inventories		**1,237**	810
Risk Management	19,20	**21**	301
Total Current Assets		**6,822**	6,473
Exploration and Evaluation Assets	1,10	**1,585**	1,575
Property, Plant and Equipment, Net	1,11	**16,426**	17,335
Risk Management	19,20	**3**	-
Income Tax Receivable		**124**	90
Other Assets		**56**	76
Goodwill	1	**242**	242
Total Assets		**25,258**	25,791
Liabilities and Shareholders' Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities		**2,266**	1,702
Income Tax Payable		**112**	133
Risk Management	19,20	**293**	23
Total Current Liabilities		**2,671**	1,858
Long-Term Debt	13	**6,332**	6,525
Risk Management	19,20	**22**	7
Decommissioning Liabilities	14	**1,847**	2,052
Other Liabilities		**211**	142
Deferred Income Taxes		**2,585**	2,816
Total Liabilities		**13,668**	13,400
Shareholders' Equity		**11,590**	12,391
Total Liabilities and Shareholders' Equity		**25,258**	25,791

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (unaudited)

($ millions)

	Share Capital	Paid in Surplus	Retained Earnings	AOCI [1]	**Total**
	(Note 15)			(Note 16)	
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**

(1) Accumulated Other Comprehensive Income (Loss).

See accompanying Notes to Consolidated Financial Statements (unaudited).

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

For the periods ended December 31,
($ millions)

	Notes	Three Months Ended 2016	2015	Twelve Months Ended 2016	2015
Operating Activities					
Net Earnings (Loss)		**91**	(641)	**(545)**	618
Depreciation, Depletion and Amortization	7,11	**(71)**	659	**1,498**	2,114
Exploration Expense	7,10	**-**	117	**2**	138
Deferred Income Taxes	8	**144**	(139)	**(209)**	(655)
Unrealized (Gain) Loss on Risk Management	19	**114**	26	**554**	195
Unrealized Foreign Exchange (Gain) Loss	4	**152**	219	**(189)**	1,097
(Gain) Loss on Divestiture of Assets	5	**-**	3	**6**	(2,392)
Current Tax on Divestiture of Assets	5	**-**	-	**-**	391
Unwinding of Discount on Decommissioning Liabilities	3,14	**33**	32	**130**	126
Onerous Contract Provisions, Net of Cash Paid		**27**	-	**53**	-
Other Asset Impairments	6	**23**	-	**30**	-
Other		**22**	(1)	**93**	59
Net Change in Other Assets and Liabilities		**(32)**	(26)	**(91)**	(107)
Net Change in Non-Cash Working Capital		**(339)**	73	**(471)**	(110)
Cash From Operating Activities		**164**	322	**861**	1,474
Investing Activities					
Capital Expenditures – Exploration and Evaluation Assets	10	**(11)**	(21)	**(67)**	(138)
Capital Expenditures – Property, Plant and Equipment	11	**(248)**	(406)	**(967)**	(1,576)
Acquisition	12	**-**	(4)	**-**	(84)
Proceeds From Divestiture of Assets	5	**-**	(1)	**8**	3,344
Current Tax on Divestiture of Assets	5	**-**	-	**-**	(391)
Net Change in Investments and Other		**(1)**	3	**(1)**	3
Net Change in Non-Cash Working Capital		**16**	(40)	**(52)**	(270)
Cash From (Used in) Investing Activities		**(244)**	(469)	**(1,079)**	888
Net Cash Provided (Used) Before Financing Activities		**(80)**	(147)	**(218)**	2,362
Financing Activities					
Net Issuance (Repayment) of Short-Term Borrowings		**-**	(6)	**-**	(25)
Common Shares Issued, Net of Issuance Costs		**-**	-	**-**	1,449
Dividends Paid on Common Shares	9	**(42)**	(132)	**(166)**	(528)
Other		**(1)**	-	**(2)**	(2)
Cash From (Used in) Financing Activities		**(43)**	(138)	**(168)**	894
Foreign Exchange Gain (Loss) on Cash and Cash Equivalents Held in Foreign Currency		**(7)**	(11)	**1**	(34)
Increase (Decrease) in Cash and Cash Equivalents		**(130)**	(296)	**(385)**	3,222
Cash and Cash Equivalents, Beginning of Period		**3,850**	4,401	**4,105**	883
Cash and Cash Equivalents, End of Period		**3,720**	4,105	**3,720**	4,105

See accompanying Notes to Consolidated Financial Statements (unaudited).

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 interim Consolidated Financial Statements is found in Note 2.

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 projects in the early stages of development, such as Grand Rapids and Telephone Lake. Certain of the Company's operated oil sands properties, notably Foster Creek, Christina Lake and Narrows Lake, are jointly owned with ConocoPhillips, an unrelated U.S. public company.
- **Conventional,** which includes the development and production of conventional crude oil, NGLs and natural gas in Alberta and Saskatchewan, including the heavy oil assets at Pelican Lake, the carbon dioxide enhanced oil recovery project at Weyburn and emerging tight oil opportunities.
- **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 operating 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.

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		Conventional		Refining and Marketing	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**957**	651	**369**	351	**2,477**	2,030
Less: Royalties	**2**	3	**51**	28	**-**	-
	955	648	**318**	323	**2,477**	2,030
Expenses						
Purchased Product	**-**	-	**-**	-	**2,181**	1,883
Transportation and Blending	**493**	478	**50**	58	**-**	-
Operating	**142**	129	**113**	130	**185**	203
Production and Mineral Taxes	**-**	-	**3**	2	**-**	-
(Gain) Loss on Risk Management	**(14)**	(152)	**(1)**	(71)	**3**	(16)
Operating Margin [1]	**334**	193	**153**	204	**108**	(40)
Depreciation, Depletion and Amortization	**170**	189	**(310)**	403	**54**	51
Exploration Expense	**-**	67	**-**	50	**-**	-
Segment Income (Loss)	**164**	(63)	**463**	(249)	**54**	(91)

(1) Previously labelled Operating Cash Flow.

	Corporate and Eliminations		Consolidated	
For the three months ended December 31,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(108)**	(77)	**3,695**	2,955
Less: Royalties	**-**	-	**53**	31
	(108)	(77)	**3,642**	2,924
Expenses				
Purchased Product	**(106)**	(75)	**2,075**	1,808
Transportation and Blending	**(2)**	(2)	**541**	534
Operating	**(1)**	(2)	**439**	460
Production and Mineral Taxes	**-**	-	**3**	2
(Gain) Loss on Risk Management	**114**	26	**102**	(213)
Depreciation, Depletion and Amortization	**15**	16	**(71)**	659
Exploration Expense	**-**	-	**-**	117
Segment Income (Loss)	**(128)**	(40)	**553**	(443)
General and Administrative	**101**	109	**101**	109
Finance Costs	**124**	123	**124**	123
Interest Income	**(7)**	(8)	**(7)**	(8)
Foreign Exchange (Gain) Loss, Net	**140**	204	**140**	204
Research Costs	**6**	7	**6**	7
(Gain) Loss on Divestiture of Assets	**-**	3	**-**	3
Other (Income) Loss, Net	**27**	1	**27**	1
	391	439	**391**	439
Earnings (Loss) Before Income Tax			**162**	(882)
Income Tax Expense (Recovery)			**71**	(241)
Net Earnings (Loss)			**91**	(641)

B) Financial Results by Upstream Product

	Crude Oil (1)					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**951**	644	**266**	239	**1,217**	883
Less: Royalties	**2**	3	**45**	25	**47**	28
	949	641	**221**	214	**1,170**	855
Expenses						
Transportation and Blending	**492**	478	**46**	53	**538**	531
Operating	**138**	124	**74**	84	**212**	208
Production and Mineral Taxes	**-**	-	**3**	2	**3**	2
(Gain) Loss on Risk Management	**(14)**	(151)	**(2)**	(57)	**(16)**	(208)
Operating Margin (2)	**333**	190	**100**	132	**433**	322

	Natural Gas					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**5**	5	**100**	104	**105**	109
Less: Royalties	**-**	-	**6**	3	**6**	3
	5	5	**94**	101	**99**	106
Expenses						
Transportation and Blending	**1**	-	**4**	5	**5**	5
Operating	**4**	3	**39**	44	**43**	47
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	(1)	**1**	(14)	**1**	(15)
Operating Margin (2)	**-**	3	**50**	66	**50**	69

	Other					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**1**	2	**3**	8	**4**	10
Less: Royalties	**-**	-	**-**	-	**-**	-
	1	2	**3**	8	**4**	10
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**-**	2	**-**	2	**-**	4
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Margin (2)	**1**	-	**3**	6	**4**	6

	Total Upstream					
	Oil Sands		Conventional		Total	
For the three months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**957**	651	**369**	351	**1,326**	1,002
Less: Royalties	**2**	3	**51**	28	**53**	31
	955	648	**318**	323	**1,273**	971
Expenses						
Transportation and Blending	**493**	478	**50**	58	**543**	536
Operating	**142**	129	**113**	130	**255**	259
Production and Mineral Taxes	**-**	-	**3**	2	**3**	2
(Gain) Loss on Risk Management	**(14)**	(152)	**(1)**	(71)	**(15)**	(223)
Operating Margin (2)	**334**	193	**153**	204	**487**	397

(1) Includes NGLs.
(2) Previously labelled Operating Cash Flow.

C) Results of Operations – Segment and Operational Information

	Oil Sands		Conventional		Refining and Marketing	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,929**	3,030	**1,267**	1,709	**8,439**	8,805
Less: Royalties	**9**	29	**139**	114	**-**	-
	2,920	3,001	**1,128**	1,595	**8,439**	8,805
Expenses						
Purchased Product	**-**	-	**-**	-	**7,325**	7,709
Transportation and Blending	**1,721**	1,815	**186**	230	**-**	-
Operating	**501**	531	**444**	561	**742**	754
Production and Mineral Taxes	**-**	-	**12**	18	**-**	-
(Gain) Loss on Risk Management	**(179)**	(404)	**(58)**	(209)	**26**	(43)
Operating Margin (1)	**877**	1,059	**544**	995	**346**	385
Depreciation, Depletion and Amortization	**655**	697	**567**	1,148	**211**	191
Exploration Expense	**2**	67	**-**	71	**-**	-
Segment Income (Loss)	**220**	295	**(23)**	(224)	**135**	194

(1) Previously labelled Operating Cash Flow.

	Corporate and Eliminations		Consolidated	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015
Revenues				
Gross Sales	**(353)**	(337)	**12,282**	13,207
Less: Royalties	**-**	-	**148**	143
	(353)	(337)	**12,134**	13,064
Expenses				
Purchased Product	**(347)**	(335)	**6,978**	7,374
Transportation and Blending	**(6)**	(2)	**1,901**	2,043
Operating	**(4)**	(7)	**1,683**	1,839
Production and Mineral Taxes	**-**	-	**12**	18
(Gain) Loss on Risk Management	**554**	195	**343**	(461)
Depreciation, Depletion and Amortization	**65**	78	**1,498**	2,114
Exploration Expense	**-**	-	**2**	138
Segment Income (Loss)	**(615)**	(266)	**(283)**	(1)
General and Administrative	**326**	335	**326**	335
Finance Costs	**492**	482	**492**	482
Interest Income	**(52)**	(28)	**(52)**	(28)
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036	**(198)**	1,036
Research Costs	**36**	27	**36**	27
(Gain) Loss on Divestiture of Assets	**6**	(2,392)	**6**	(2,392)
Other (Income) Loss, Net	**34**	2	**34**	2
	644	(538)	**644**	(538)
Earnings (Loss) Before Income Tax			**(927)**	537
Income Tax Expense (Recovery)			**(382)**	(81)
Net Earnings (Loss)			**(545)**	618

D) Financial Results by Upstream Product

	Crude Oil [1]					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,911**	3,000	**936**	1,239	**3,847**	4,239
Less: Royalties	**9**	29	**125**	103	**134**	132
	2,902	2,971	**811**	1,136	**3,713**	4,107
Expenses						
Transportation and Blending	**1,720**	1,814	**170**	213	**1,890**	2,027
Operating	**486**	511	**287**	381	**773**	892
Production and Mineral Taxes	**-**	-	**12**	16	**12**	16
(Gain) Loss on Risk Management	**(179)**	(400)	**(60)**	(157)	**(239)**	(557)
Operating Margin [2]	**875**	1,046	**402**	683	**1,277**	1,729

	Natural Gas					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**16**	22	**321**	450	**337**	472
Less: Royalties	**-**	-	**14**	11	**14**	11
	16	22	**307**	439	**323**	461
Expenses						
Transportation and Blending	**1**	1	**16**	17	**17**	18
Operating	**11**	15	**152**	175	**163**	190
Production and Mineral Taxes	**-**	-	**-**	2	**-**	2
(Gain) Loss on Risk Management	**-**	(4)	**2**	(52)	**2**	(56)
Operating Margin [2]	**4**	10	**137**	297	**141**	307

	Other					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2**	8	**10**	20	**12**	28
Less: Royalties	**-**	-	**-**	-	**-**	-
	2	8	**10**	20	**12**	28
Expenses						
Transportation and Blending	**-**	-	**-**	-	**-**	-
Operating	**4**	5	**5**	5	**9**	10
Production and Mineral Taxes	**-**	-	**-**	-	**-**	-
(Gain) Loss on Risk Management	**-**	-	**-**	-	**-**	-
Operating Margin [2]	**(2)**	3	**5**	15	**3**	18

	Total Upstream					
	Oil Sands		Conventional		Total	
For the twelve months ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Revenues						
Gross Sales	**2,929**	3,030	**1,267**	1,709	**4,196**	4,739
Less: Royalties	**9**	29	**139**	114	**148**	143
	2,920	3,001	**1,128**	1,595	**4,048**	4,596
Expenses						
Transportation and Blending	**1,721**	1,815	**186**	230	**1,907**	2,045
Operating	**501**	531	**444**	561	**945**	1,092
Production and Mineral Taxes	**-**	-	**12**	18	**12**	18
(Gain) Loss on Risk Management	**(179)**	(404)	**(58)**	(209)	**(237)**	(613)
Operating Margin [2]	**877**	1,059	**544**	995	**1,421**	2,054

(1) Includes NGLs.
(2) Previously labelled Operating Cash Flow.

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

	E&E [1]		PP&E [2]	
As at December 31,	**2016**	2015	**2016**	2015
Oil Sands	**1,564**	1,560	**8,798**	8,907
Conventional	**21**	15	**3,080**	3,720
Refining and Marketing	**-**	-	**4,273**	4,398
Corporate and Eliminations	**-**	-	**275**	310
Consolidated	**1,585**	1,575	**16,426**	17,335

	Goodwill		Total Assets	
As at December 31,	**2016**	2015	**2016**	2015
Oil Sands	**242**	242	**11,112**	11,069
Conventional	**-**	-	**3,196**	3,830
Refining and Marketing	**-**	-	**6,613**	5,844
Corporate and Eliminations	**-**	-	**4,337**	5,048
Consolidated	**242**	242	**25,258**	25,791

(1) Exploration and Evaluation ("E&E") assets.
(2) Property, Plant and Equipment ("PP&E").

F) Geographical Information

	Revenues			
	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Canada	**1,966**	1,367	**6,106**	6,264
United States	**1,676**	1,557	**6,028**	6,800
Consolidated	**3,642**	2,924	**12,134**	13,064

	Non-Current Assets [3]	
As at December 31,	**2016**	2015
Canada	**14,130**	14,921
United States	**4,179**	4,307
Consolidated	**18,309**	19,228

(3) Includes E&E, PP&E, goodwill and other assets.

G) Capital Expenditures [4]

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Capital				
Oil Sands	**128**	239	**604**	1,185
Conventional	**57**	87	**171**	244
Refining and Marketing	**65**	89	**220**	248
Corporate	**9**	13	**31**	37
Capital Investment	**259**	428	**1,026**	1,714
Acquisition Capital				
Oil Sands	**-**	3	**11**	3
Conventional	**-**	-	**-**	1
Refining and Marketing	**-**	-	**-**	83
Total Capital Expenditures	**259**	431	**1,037**	1,801

(4) Includes expenditures on PP&E and E&E.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

In these interim 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 interim Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, including International Accounting Standard 34, "*Interim Financial Reporting*" ("IAS 34"), and have been prepared following the same accounting policies and methods of computation as the annual Consolidated Financial Statements for the year ended December 31, 2015, except for income taxes. Income taxes on earnings or loss in the interim periods are accrued using the income tax rate that would be applicable to the expected total annual earnings or loss. Certain information and disclosures normally included in the notes to the annual Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with the annual Consolidated Financial Statements for the year ended December 31, 2015, which have been prepared in accordance with IFRS as issued by the IASB.

These interim Consolidated Financial Statements were approved by the Audit Committee effective February 15, 2017.

3. FINANCE COSTS

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Interest Expense – Short-Term Borrowings and Long-Term Debt	**86**	85	**341**	328
Unwinding of Discount on Decommissioning Liabilities (Note 14)	**33**	32	**130**	126
Other	**5**	6	**21**	28
	124	123	**492**	482

4. FOREIGN EXCHANGE (GAIN) LOSS, NET

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Unrealized Foreign Exchange (Gain) Loss on Translation of:				
U.S. Dollar Debt Issued From Canada	**147**	212	**(196)**	1,064
Other	**5**	7	**7**	33
Unrealized Foreign Exchange (Gain) Loss	**152**	219	**(189)**	1,097
Realized Foreign Exchange (Gain) Loss	**(12)**	(15)	**(9)**	(61)
	140	204	**(198)**	1,036

5. DIVESTITURES

In the third quarter of 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. In the second quarter of 2016, the Company sold equipment at a loss of $1 million. These assets, related liabilities and results of operations were reported in the Conventional segment.

In the third quarter of 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.

The divestiture 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 has been classified as an investing activity in the Consolidated Statements of Cash Flows.

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

6. 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 has written off $23 million of capitalized costs associated with its funding support unit in Northern Gateway Pipeline. In addition, $7 million of expected costs associated with termination have been recorded.

In 2016, $7 million (2015 – $nil) of certain investments in private equity companies were written off.

7. IMPAIRMENT CHARGES AND REVERSALS

A) Cash-Generating Unit ("CGU") Net Impairments

The review of the Company's PP&E and E&E assets for indicators of impairment as at December 31, 2016 provided evidence that a portion of the impairment losses previously recorded should be reversed.

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 depreciation, depletion and amortization ("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. The Northern Alberta CGU includes 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 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. The Suffield CGU includes production of natural gas and heavy crude oil in Alberta on the Canadian Forces Base.

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, 2016.

Key Assumptions

The recoverable amounts of Cenovus's upstream CGUs were determined based on fair value less costs of disposal ("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 independent qualified reserves evaluators ("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, 2016 by the IQREs.

Crude Oil and Natural Gas Prices

The 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$/barrel) [(1)]	55.00	58.70	62.40	69.00	75.80	2.0%
WCS (C$/barrel) [(2)]	53.70	58.20	61.90	66.50	71.00	2.0%
AECO (C$/Mcf) [(3)] [(4)]	3.40	3.15	3.30	3.60	3.90	2.2%

(1) West Texas Intermediate ("WTI") crude oil.
(2) Western Canadian Select ("WCS") crude oil blend.
(3) Alberta Energy Company ("AECO") natural gas.
(4) Assumes gas heating value of one million British Thermal Units per thousand cubic feet.

Discount and Inflation Rates

Evaluations of discounted future cash flows are initiated using the discount rate of 10 percent and inflation is estimated at two percent, which is common industry practice and used by Cenovus's IQREs in preparing the reserves report. Based on the individual characteristics of the CGU, other economic and operating factors are also considered, which may increase or decrease the implied discount rate.

Sensitivities

The estimated recoverable value of the Northern Alberta CGU is sensitive to discount rate and forward price estimates over the life of the reserves. Changes to these assumptions, assuming all other variables remained constant, would have had the following impact on the 2016 net impairment of the Northern Alberta CGU:

	One Percent Increase in the Discount Rate	One Percent Decrease in the Discount Rate [1]	Five Percent Increase in the Forward Price Estimates [1]	Five Percent Decrease in the Forward Price Estimates
Increase (Decrease) to Net Impairment of PP&E	**132**	**(106)**	**(106)**	**270**

(1) *The $106 million represents the remaining impairment loss that could be reversed as at December 31, 2016.*

2015 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. 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

Exploration and Evaluation Assets

In 2016, $2 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable. This impairment loss was recorded as exploration expense in the Oil Sands segment.

In 2015, $138 million of previously capitalized E&E costs were deemed not to be technically feasible and commercially viable, and were recorded as exploration expense. This impairment loss included $67 million and $71 million within the Oil Sands and Conventional segments, respectively.

Property, Plant and Equipment, Net

In the fourth quarter of 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.

In the third quarter of 2016, the Company 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. In the second quarter of 2016, $4 million of leasehold improvements were written off. This impairment loss was 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.

8. INCOME TAXES

The provision for income taxes is:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Current Tax				
Canada	**(73)**	(100)	**(174)**	586
United States	**-**	(2)	**1**	(12)
Total Current Tax Expense (Recovery)	**(73)**	(102)	**(173)**	574
Deferred Tax Expense (Recovery)	**144**	(139)	**(209)**	(655)
	71	(241)	**(382)**	(81)

In 2016, the Company recorded a current tax recovery due to the carryback of losses for income tax purposes and prior year adjustments.

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 Refining LP ("WRB") which, due to an election filed with the U.S. tax authorities, was added to the tax basis of WRB's assets. The Government of Alberta enacted a two percent increase in the corporate income tax rate effective July 1, 2015, increasing the statutory tax rate for the year to 26.1 percent. As a result, the Company's deferred income tax liability increased by $161 million for the year ended December 31, 2015.

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

For the twelve months ended December 31,	**2016**	2015
Earnings (Loss) Before Income Tax	**(927)**	537
Canadian Statutory Rate	**27.0%**	26.1%
Expected Income Tax (Recovery)	**(250)**	140
Effect of Taxes Resulting From:		
Foreign Tax Rate Differential	**(46)**	(41)
Non-Deductible Stock-Based Compensation	**5**	7
Non-Taxable Capital (Gains) Losses	**(26)**	137
Unrecognized Capital (Gains) Losses Arising From Unrealized Foreign Exchange	**(26)**	135
Adjustments Arising From Prior Year Tax Filings	**(46)**	(55)
Derecognition (Recognition) of Capital Losses	**-**	(149)
(Recognition) of U.S. Tax Basis	**-**	(415)
Change in Statutory Rate	**-**	161
Other	**7**	(1)
Total Tax (Recovery)	**(382)**	(81)
Effective Tax Rate	**41.2%**	(15.1)%

9. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Share

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Net Earnings (Loss) – Basic and Diluted ($ millions)	**91**	(641)	**(545)**	618
Weighted Average Number of Shares – Basic and Diluted (millions)	**833.3**	833.3	**833.3**	818.7
Net Earnings (Loss) Per Share – Basic and Diluted ($)	**0.11**	(0.77)	**(0.65)**	0.75

B) Dividends Per Share

For the twelve months ended December 31, 2016, the Company paid dividends of $166 million or $0.20 per share, all of which were paid in cash (twelve months ended December 31, 2015 – $710 million or $0.8524 per share, including cash dividends of $528 million).

10. EXPLORATION AND EVALUATION ASSETS

	Total
As at December 31, 2015	1,575
Additions	67
Transfers to PP&E (Note 11)	(49)
Exploration Expense (Note 7)	(2)
Change in Decommissioning Liabilities	(6)
As at December 31, 2016	**1,585**

11. 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 10)	49	-	-	-	49
Change in Decommissioning Liabilities	(267)	-	(8)	-	(275)
Exchange Rate Movements and Other	(16)	-	(152)	(1)	(169)
Divestitures (Note 5)	(23)	-	-	-	(23)
As at December 31, 2016	**31,941**	**333**	**5,259**	**1,074**	**38,607**
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 7)	481	-	-	4	485
Reversal of Impairment Losses (Note 7)	(462)	-	-	-	(462)
Exchange Rate Movements and Other	(4)	-	(25)	-	(29)
Divestitures (Note 5)	(8)	-	-	-	(8)
As at December 31, 2016	**20,088**	**308**	**1,076**	**709**	**22,181**
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**

(1) Includes crude-by-rail terminal, office furniture, fixtures, leasehold improvements, information technology and aircraft.

12. ACQUISITION

In 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.

13. LONG-TERM DEBT

As at December 31,	US$ Principal	2016	2015
Revolving Term Debt [(1)]	**-**	**-**	-
U.S. Dollar Denominated Unsecured Notes	**4,750**	**6,378**	6,574
Total Debt Principal		**6,378**	6,574
Debt Discounts and Transaction Costs		**(46)**	(49)
		6,332	6,525

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

On February 24, 2016, Cenovus filed a base shelf prospectus. The base shelf prospectus allows the Company to offer, from time to time, up to US$5.0 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 will expire in March 2018. As at December 31, 2016, no issuances have been made under the US$5.0 billion base shelf prospectus.

On April 22, 2016, the Company renegotiated the maturity date of the $1.0 billion tranche of its committed credit facility from November 30, 2017 to April 30, 2019. As at December 31, 2016, Cenovus had $4.0 billion available on its committed credit facility.

As at December 31, 2016, the Company is in compliance with all of the terms of its debt agreements.

14. 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:

	Total
As at December 31, 2015	2,052
Liabilities Incurred	11
Liabilities Settled	(51)
Liabilities Divested	(1)
Change in Estimated Future Cash Flows	(423)
Change in Discount Rate	131
Unwinding of Discount on Decommissioning Liabilities	130
Foreign Currency Translation	(2)
As at December 31, 2016	**1,847**

The undiscounted amount of estimated future cash flows required to settle the obligation has been discounted using a credit-adjusted risk-free rate of 5.9 percent as at December 31, 2016 (December 31, 2015 – 6.4 percent).

15. 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

As at December 31, 2016	**Number of Common Shares** (thousands)	**Amount**
Outstanding, Beginning of Year and End of Year	**833,290**	**5,534**

There were no preferred shares outstanding as at December 31, 2016 (December 31, 2015 – nil).

As at December 31, 2016, there were 12 million (December 31, 2015 – 12 million) common shares available for future issuance under the stock option plan.

16. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Defined Benefit Plan	Foreign Currency Translation	Available for Sale Financial Assets	Total
As at December 31, 2014	(30)	427	10	407
Other Comprehensive Income (Loss), Before Tax	28	587	8	623
Income Tax	(8)	-	(2)	(10)
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**

17. STOCK-BASED COMPENSATION PLANS

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"). The following table summarizes information related to Cenovus's stock-based compensation plans:

As at December 31, 2016	Units Outstanding (thousands)	Units Exercisable (thousands)
NSRs	**41,644**	**30,006**
TSARs	**3,373**	**3,373**
PSUs	**6,157**	**-**
RSUs	**3,790**	**-**
DSUs	**1,598**	**1,598**

For the twelve months ended December 31, 2016	Units Granted (thousands)	Units Vested and Paid Out (thousands)
NSRs	**3,646**	**-**
PSUs	**2,345**	**979**
RSUs	**1,718**	**32**
DSUs	**103**	**10**

The weighted average exercise price of NSRs and TSARs as at December 31, 2016 was $30.57 and $26.66, respectively.

The following table summarizes the stock-based compensation expense (recovery) recorded for all plans:

	Three Months Ended		Twelve Months Ended	
For the periods ended December 31,	**2016**	2015	**2016**	2015
NSRs	**3**	7	**15**	27
TSARs	**(1)**	(1)	**(1)**	(5)
PSUs	**6**	(6)	**13**	(13)
RSUs	**5**	1	**13**	6
DSUs	**3**	(4)	**7**	(5)
Stock-Based Compensation Expense (Recovery)	**16**	(3)	**47**	10
Stock-Based Compensation Costs Capitalized	**4**	-	**12**	6
Total Stock-Based Compensation	**20**	(3)	**59**	16

18. CAPITAL STRUCTURE

Cenovus's capital structure objectives and targets have remained unchanged from previous periods. Cenovus's capital structure consists of Shareholders' Equity plus Debt. Debt is defined as short-term borrowings, and the current and long-term portions of long-term 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'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 Debt to Capitalization and Debt to Adjusted Earnings Before Interest, Taxes and DD&A ("Adjusted EBITDA"). 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 Debt to Capitalization ratio of between 30 and 40 percent and a Debt to Adjusted EBITDA ratio of between 1.0 and 2.0 times. At different points within the economic cycle, Cenovus expects these ratios may periodically be outside of the target range.

A) Debt to Capitalization and Net Debt to Capitalization

As at December 31,	**2016**	2015
Debt	**6,332**	6,525
Shareholders' Equity	**11,590**	12,391
	17,922	18,916
Debt to Capitalization	**35%**	34%
Debt	**6,332**	6,525
Add (Deduct):		
Cash and Cash Equivalents	**(3,720)**	(4,105)
Net Debt	**2,612**	2,420
Shareholders' Equity	**11,590**	12,391
	14,202	14,811
Net Debt to Capitalization	**18%**	16%

B) Debt to Adjusted EBITDA and Net Debt to Adjusted EBITDA

As at December 31,	**2016**	2015
Debt	**6,332**	6,525
Net Debt	**2,612**	2,420
Net Earnings (Loss)	**(545)**	618
Add (Deduct):		
Finance Costs	**492**	482
Interest Income	**(52)**	(28)
Income Tax Expense (Recovery)	**(382)**	(81)
DD&A	**1,498**	2,114
E&E Impairment	**2**	138
Unrealized (Gain) Loss on Risk Management	**554**	195
Foreign Exchange (Gain) Loss, Net	**(198)**	1,036
(Gain) Loss on Divestitures of Assets	**6**	(2,392)
Other (Income) Loss, Net	**34**	2
Adjusted EBITDA (1)	**1,409**	2,084
Debt to Adjusted EBITDA	**4.5x**	3.1x
Net Debt to Adjusted EBITDA	**1.9x**	1.2x

(1) *Calculated on a trailing twelve-month basis.*

Cenovus will 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 manage its capital structure, Cenovus may, among other actions, adjust capital and operating spending, adjust dividends paid to shareholders, purchase shares for cancellation pursuant to normal course issuer bids, issue new shares, issue new debt, draw down on its credit facility or repay existing debt.

Effective April 22, 2016, the Company extended the maturity date of the $1.0 billion tranche of the committed credit facility from November 30, 2017 to April 30, 2019. As at December 31, 2016, Cenovus had $4.0 billion available on its committed credit facility. In addition, Cenovus has in place a US$5.0 billion base shelf prospectus, the availability of which is dependent on market conditions.

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.

As at December 31, 2016, Cenovus is in compliance with all of the terms of its debt agreements.

19. 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, 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, 2016, the carrying value of Cenovus's long-term debt was $6,332 million and the fair value was $6,539 million (December 31, 2015 carrying value – $6,525 million, fair value – $6,050 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:

	Total
Fair Value, as at December 31, 2015	**42**
Change in Fair Value (1)	**(4)**
Impairment Losses (2)	**(3)**
Fair Value, as at December 31, 2016	**35**

(1) Changes in fair value on available for sale financial assets are recorded in other comprehensive income.
(2) Impairment losses on available for sale financial assets are reclassified from other comprehensive income 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, condensate, power purchase contracts 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 power purchase contracts are calculated internally based on observable and unobservable inputs such as forward power prices in less active markets (Level 3). The unobservable inputs are obtained from third parties whenever possible and reviewed by the Company for reasonableness. 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

	2016			2015		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Commodity Prices						
Crude Oil	**21**	**307**	**(286)**	301	15	286
Power	**-**	**-**	**-**	-	13	(13)
	21	**307**	**(286)**	301	28	273
Interest Rate	**3**	**8**	**(5)**	-	2	(2)
Total Fair Value	**24**	**315**	**(291)**	301	30	271

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

As at December 31,	**2016**	2015
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(291)**	284
Level 3 – Prices Determined From Unobservable Inputs	**-**	(13)
	(291)	271

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. Prices determined from unobservable inputs refers to the fair value of contracts valued using data that is both unobservable and significant to the overall fair value measurement.

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities from January 1 to December 31:

	2016	2015
Fair Value of Contracts, Beginning of Year	**271**	462
Fair Value of Contracts Realized During the Year (1)	**(211)**	(656)
Change in Fair Value of Contracts in Place at Beginning of Year and Contracts Entered Into During the Year (2)	**(343)**	461
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**(8)**	4
Fair Value of Contracts, End of Year	**(291)**	271

(1) Includes a realized loss of $6 million related to power contracts (2015 – $10 million loss).
(2) Includes an increase of $7 million related to power contracts (2015 – $14 million decrease).

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

	Three Months Ended		**Twelve Months Ended**	
For the periods ended December 31,	**2016**	2015	**2016**	2015
Realized (Gain) Loss (1)	**(12)**	(239)	**(211)**	(656)
Unrealized (Gain) Loss (2)	**114**	26	**554**	195
(Gain) Loss on Risk Management	**102**	(213)	**343**	(461)

(1) Realized gains and losses on risk management are recorded in the operating segment to which the derivative instrument relates.
(2) Unrealized gains and losses on risk management are recorded in the Corporate and Eliminations segment.

20. 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. A description of the nature and extent of risks arising from the Company's financial assets and liabilities can be found in the notes to the annual Consolidated Financial Statements as at December 31, 2015. Exposure to these risks has not changed significantly since December 31, 2015. 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, 2016, Cenovus had a notional amount of US$400 million in interest rate swaps.

Net Fair Value of Risk Management Positions

As at December 31, 2016	Notional Volumes	Terms	Average Price	Fair Value
Crude Oil Contracts				
Fixed Price Contracts				
Brent Fixed Price	10,000 bbls/d	July – December 2017	US$53.09/bbl	**(14)**
Brent Fixed Price	10,000 bbls/d	January – June 2018	US$54.06/bbl	**(11)**
WTI Fixed Price	70,000 bbls/d	January – June 2017	US$46.35/bbl	**(159)**
WTI Collars	50,000 bbls/d	July – December 2017	US$44.84 – US$56.47/bbl	**(52)**
WTI Collars	10,000 bbls/d	January – June 2018	US$45.30 – US$62.77/bbl	**(3)**
Other Financial Positions (1)				**(47)**
Crude Oil Fair Value Position				**(286)**
Interest Rate Swaps				**(5)**
Total Fair Value				**(291)**

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

Sensitivities – Risk Management Positions

The following table summarizes the sensitivity of the fair value of Cenovus's risk management positions to fluctuations in commodity prices or interest rates, 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 or interest rates on the Company's open risk management positions could have resulted in unrealized gains (losses) impacting earnings before income tax as follows:

Risk Management Positions in Place 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)**
Interest Rate Swaps	± 50 Basis Points	**45**	**(52)**

21. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations primarily related to demand charges on firm transportation agreements. In addition, the Company has commitments related to its risk management program and an obligation to fund its defined benefit pension and other post-employment benefit plans. Additional information related to the Company's commitments can be found in the notes to the annual Consolidated Financial Statements for the year ended December 31, 2015.

For the year ended December 31, 2016, the Company's transportation commitments decreased approximately $1.1 billion primarily due to the use of contracts and changes in toll estimates. These agreements, some of which are subject to regulatory approval, are for terms up to 20 years subsequent to the date of commencement. As at December 31, 2016, total transportation commitments were $26 billion.

As at December 31, 2016, there were outstanding letters of credit aggregating $258 million issued as security for performance under certain contracts (December 31, 2015 – $64 million).

B) 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.