MANAGEMENT'S REPORT

The management of Husky Energy Inc. ("the Company") is responsible for the financial information and operating data presented in this financial document.

The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this financial document has been prepared on a basis consistent with that in the consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Company's internal control over financial reporting was effective as of December 31, 2016. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, internal auditors as well as the external auditors, to discuss audit (external, internal and joint venture), internal controls, accounting policy and financial reporting matters as well as the reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board. The Committee is also responsible for the appointment of the external auditors for the Company.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian Auditing Standards and the standards of the Public Company Accounting Oversight Board (United States) on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

"Robert J. Peabody"

Robert J. Peabody

President & Chief Executive Officer

"Jonathan M. McKenzie"

Jonathan M. McKenzie

Chief Financial Officer

Calgary, Canada

February 23, 2017

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated financial statements of Husky Energy Inc., which comprise the consolidated balance sheets as at December 31, 2016 and December 31, 2015, the consolidated statements of income (loss), comprehensive income (loss), changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Husky Energy Inc. as at December 31, 2016 and December 31, 2015, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

"KPMG LLP"

KPMG LLP

Chartered Professional Accountants

February 23, 2017

Calgary, Canada

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2016**	December 31, 2015
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**1,319**	70
Accounts receivable *(notes 5, 24)*	**1,036**	1,014
Income taxes receivable	**186**	312
Inventories *(note 6)*	**1,558**	1,247
Prepaid expenses	**135**	271
Restricted cash *(note 7, 16)*	**84**	—
	4,318	2,914
Restricted cash *(note 7, 16)*	**72**	121
Exploration and evaluation assets *(note 8)*	**1,066**	1,091
Property, plant and equipment, net *(note 9)*	**24,593**	27,634
Goodwill *(note 10)*	**679**	700
Investment in joint ventures *(note 11)*	**1,128**	359
Long-term income taxes receivable	**232**	109
Other assets *(note 12)*	**172**	128
Total Assets	**32,260**	33,056
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 14)*	**2,226**	2,527
Short-term debt *(note 15)*	**200**	720
Long-term debt due within one year *(note 15)*	**403**	277
Contribution payable due within one year *(note 11)*	**146**	210
Asset retirement obligations *(note 16)*	**218**	102
	3,193	3,836
Long-term debt *(note 15)*	**4,736**	5,759
Other long-term liabilities *(note 17)*	**1,020**	743
Contribution payable *(note 11)*	**—**	138
Asset retirement obligations *(note 16)*	**2,573**	2,882
Deferred tax liabilities *(note 18)*	**3,111**	3,112
Total Liabilities	**14,633**	16,470
Shareholders' equity		
Common shares *(note 19)*	**7,296**	7,000
Preferred shares *(note 19)*	**874**	874
Retained earnings	**8,457**	7,589
Other reserves	**989**	1,123
Non-controlling interest	**11**	—
Total Shareholders' Equity	**17,627**	16,586
Total Liabilities and Shareholders' Equity	**32,260**	33,056

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

"Robert J. Peabody"

Robert J. Peabody
Director

"William Shurniak"

William Shurniak
Director

Consolidated Statements of Income (Loss)

	Year ended December 31,	
(millions of Canadian dollars, except share data)	**2016**	2015
Gross revenues	**13,312**	16,763
Royalties	**(305)**	(432)
Marketing and other	**(88)**	38
Revenues, net of royalties	**12,919**	16,369
Expenses		
Purchases of crude oil and products	**7,356**	9,397
Production, operating and transportation expenses *(note 20)*	**2,724**	2,994
Selling, general and administrative expenses *(note 20)*	**544**	342
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**2,462**	8,644
Exploration and evaluation expenses *(note 8)*	**188**	447
Gain on sale of assets *(note 9)*	**(1,634)**	(22)
Other – net	**(27)**	(287)
	11,613	21,515
Earnings (loss) from operating activities	**1,306**	(5,146)
Share of equity investment gain (loss) *(note 11)*	**15**	(5)
Financial items *(note 21)*		
Net foreign exchange gains	**13**	43
Finance income	**17**	35
Finance expenses	**(401)**	(298)
	(371)	(220)
Earnings (loss) before income taxes	**950**	(5,371)
Provisions for (recovery of) income taxes *(note 18)*		
Current	**(1)**	306
Deferred	**29**	(1,827)
	28	(1,521)
Net earnings (loss)	**922**	(3,850)
Earnings (loss) per share *(note 19)*		
Basic	**0.88**	(3.95)
Diluted	**0.88**	(4.01)
Weighted average number of common shares outstanding *(note 19)*		
Basic *(millions)*	**1,004.9**	984.1
Diluted *(millions)*	**1,004.9**	984.1

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Comprehensive Income (Loss)

(millions of Canadian dollars)	Year ended December 31, 2016	2015
Net earnings (loss)	**922**	(3,850)
Other comprehensive income (loss)		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans *(note 22)*	**(18)**	(10)
Items that may be reclassified into earnings, net of tax *(note 18)*:		
Derivatives designated as cash flow hedges *(note 24)*	**(2)**	(3)
Equity investment - share of other comprehensive income	**2**	—
Exchange differences on translation of foreign operations	**(247)**	1,324
Hedge of net investment *(note 24)*	**113**	(587)
Other comprehensive income (loss)	**(152)**	724
Comprehensive income (loss)	**770**	(3,126)

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

	Attributable to Equity Holders						
				Other Reserves			
(millions of Canadian dollars)	Common Shares	Preferred Shares	Retained Earnings	Foreign Currency Translation	Hedging	Non-Controlling Interest	Total Shareholders' Equity
Balance as at December 31, 2014	6,986	534	12,666	366	23	—	20,575
Net loss	—	—	(3,850)	—	—	—	(3,850)
Other comprehensive income (loss)							
Remeasurements of pension plans (net of tax recovery of $3 million) *(note 18, 22)*	—	—	(10)	—	—	—	(10)
Derivatives designated as cash flow hedges (net of tax recovery of $1 million) *(note 18, 24)*	—	—	—	—	(3)	—	(3)
Exchange differences on translation of foreign operations (net of tax of $215 million) *(note 18)*	—	—	—	1,324	—	—	1,324
Hedge of net investment (net of tax recovery of $92 million) *(note 18, 24)*	—	—	—	(587)	—	—	(587)
Total comprehensive income (loss)	—	—	(3,860)	737	(3)	—	(3,126)
Transactions with owners recognized directly in equity:							
Preferred shares issuance *(note 19)*	—	350	—	—	—	—	350
Share issue costs *(note 19)*	—	(10)	—	—	—	—	(10)
Stock dividends paid *(note 19)*	14	—	—	—	—	—	14
Dividends declared on common shares *(note 19)*	—	—	(1,181)	—	—	—	(1,181)
Dividends declared on preferred shares *(note 19)*	—	—	(36)	—	—	—	(36)
Balance as at December 31, 2015	7,000	874	7,589	1,103	20	—	16,586
Net earnings	**—**	**—**	**922**	**—**	**—**	**—**	**922**
Other comprehensive income (loss)							
Remeasurements of pension plans (net of tax recovery of $6 million) *(note 18, 22)*	**—**	**—**	**(18)**	**—**	**—**	**—**	**(18)**
Derivatives designated as cash flow hedges (net of tax recovery of less than $1 million) *(note 18, 24)*	**—**	**—**	**—**	**—**	**(2)**	**—**	**(2)**
Equity investment - share of other comprehensive income	**—**	**—**	**—**	**—**	**2**	**—**	**2**
Exchange differences on translation of foreign operations (net of tax recovery of $40 million) *(note 18)*	**—**	**—**	**—**	**(247)**	**—**	**—**	**(247)**
Hedge of net investment (net of tax of $17 million) *(note 18, 24)*	**—**	**—**	**—**	**113**	**—**	**—**	**113**
Total comprehensive income (loss)	**—**	**—**	**904**	**(134)**	**—**	**—**	**770**
Transactions with owners recognized directly in equity:							
Stock dividends paid *(note 19)*	**296**	**—**	**—**	**—**	**—**	**—**	**296**
Dividends declared on preferred shares *(note 19)*	**—**	**—**	**(36)**	**—**	**—**	**—**	**(36)**
Non-Controlling Interest in Subsidiary	**—**	**—**	**—**	**—**	**—**	**11**	**11**
Balance as at December 31, 2016	**7,296**	**874**	**8,457**	**969**	**20**	**11**	**17,627**

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

(millions of Canadian dollars)	Year ended December 31, **2016**	2015
Operating activities		
Net earnings (loss)	**922**	(3,850)
Items not affecting cash:		
Accretion *(note 21)*	**126**	121
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**2,462**	8,644
Inventory write-down to net realizable value *(note 6)*	**9**	22
Exploration and evaluation expenses *(note 8)*	**86**	242
Deferred income taxes *(note 18)*	**29**	(1,827)
Foreign exchange	**(4)**	27
Stock-based compensation *(note 19, 20)*	**33**	(39)
Gain on sale of assets *(note 9)*	**(1,634)**	(22)
Unrealized mark to market	**38**	(14)
Other	**9**	25
Settlement of asset retirement obligations *(note 16)*	**(87)**	(98)
Deferred revenue *(note 17)*	**209**	102
Income taxes received (paid)	**3**	(227)
Interest received	**5**	3
Change in non-cash working capital *(note 23)*	**(235)**	651
Cash flow – operating activities	**1,971**	3,760
Financing activities		
Long-term debt issuance *(note 15)*	**6,181**	9,449
Long-term debt repayment *(note 15)*	**(6,949)**	(8,500)
Short-term debt *(note 15)*	**(520)**	(175)
Debt issue costs	**—**	(7)
Proceeds from preferred share issuance, net of share issue costs *(note 19)*	**—**	340
Dividends on common shares *(note 19)*	**—**	(1,167)
Dividends on preferred shares *(note 19)*	**(27)**	(36)
Interest paid	**(349)**	(323)
Other	**21**	30
Change in non-cash working capital *(note 23)*	**281**	179
Cash flow – financing activities	**(1,362)**	(210)
Investing activities		
Capital expenditures	**(1,705)**	(3,005)
Proceeds from asset sales *(note 9)*	**2,935**	122
Contribution payable payment *(note 11)*	**(193)**	(1,363)
Contribution to joint ventures *(note 11)*	**(102)**	(122)
Other	**(30)**	(117)
Change in non-cash working capital *(note 23)*	**(273)**	(332)
Cash flow – investing activities	**632**	(4,817)
Increase (decrease) in cash and cash equivalents	**1,241**	(1,267)
Effect of exchange rates on cash and cash equivalents	**8**	70
Cash and cash equivalents at beginning of year	**70**	1,267
Cash and cash equivalents at end of year	**1,319**	70

The accompanying notes to the consolidated financial statements are an integral part of these statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Description of Business and Segmented Disclosures

Husky Energy Inc. ("Husky" or "the Company") is an international integrated energy company incorporated under the Business Corporations Act (Alberta). The Company's common shares are listed on the Toronto Stock Exchange ("TSX") under the symbol "HSE" and the Cumulative Redeemable Preferred Shares, Series 1, Cumulative Redeemable Preferred Shares, Series 2, Cumulative Redeemable Preferred Shares, Series 3, Cumulative Redeemable Preferred Shares, Series 5 and Cumulative Redeemable Preferred Shares, Series 7 are listed under the symbols, "HSE.PR.A","HSE.PR.B", "HSE.PR.C", "HSE.PR.E" and "HSE.PR.G", respectively. The registered office is located at 707, 8th Avenue S.W., PO Box 6525, Station D, Calgary, Alberta, T2P 3G7.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments – Upstream and Downstream.

Upstream includes exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") (Exploration and Production) and marketing of the Company's and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and natural gas, and storage of crude oil, diluent and natural gas (Infrastructure and Marketing). Infrastructure and Marketing markets and distributes products to customers on behalf of Exploration and Production and is grouped in the Upstream business segment based on the nature of its interconnected operations. The Company's Upstream operations are located primarily in Western Canada, offshore East Coast of Canada (Atlantic Region) and offshore China and offshore Indonesia (Asia Pacific Region).

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil in Canada (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market gasoline, jet fuel and diesel fuels that meet U.S. clean fuels standards (U.S. Refining and Marketing). Upgrading, Canadian Refined Products and U.S. Refining and Marketing all process and refine natural resources into marketable products and therefore are grouped together as the Downstream business segment due to the similar nature of their products and services.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Gross revenues	**4,036**	5,374	**955**	1,264	**4,991**	6,638
Royalties	**(305)**	(432)	**—**	—	**(305)**	(432)
Marketing and other	**—**	—	**(88)**	38	**(88)**	38
Revenues, net of royalties	**3,731**	4,942	**867**	1,302	**4,598**	6,244
Expenses						
Purchases of crude oil and products	**32**	41	**857**	1,123	**889**	1,164
Production, operating and transportation expenses	**1,760**	2,076	**20**	37	**1,780**	2,113
Selling, general and administrative expenses	**232**	237	**5**	7	**237**	244
Depletion, depreciation, amortization and impairment	**1,815**	7,993	**13**	25	**1,828**	8,018
Exploration and evaluation expenses	**188**	447	**—**	—	**188**	447
Gain on sale of assets	**(192)**	(17)	**(1,439)**	—	**(1,631)**	(17)
Other – net	**53**	(34)	**(3)**	(5)	**50**	(39)
	3,888	10,743	**(547)**	1,187	**3,341**	11,930
Earnings (loss) from operating activities	**(157)**	(5,801)	**1,414**	115	**1,257**	(5,686)
Share of equity investment gain (loss)	**(1)**	(5)	**16**	—	**15**	(5)
Financial items						
Net foreign exchange gains	**—**	—	**—**	—	**—**	—
Finance income	**5**	3	**—**	—	**5**	3
Finance expenses	**(145)**	(142)	**—**	—	**(145)**	(142)
	(140)	(139)	**—**	—	**(140)**	(139)
Earnings (loss) before income taxes	**(298)**	(5,945)	**1,430**	115	**1,132**	(5,830)
Provisions for (recovery of) income taxes						
Current	**(100)**	(41)	**—**	222	**(100)**	181
Deferred	**19**	(1,566)	**122**	(191)	**141**	(1,757)
	(81)	(1,607)	**122**	31	**41**	(1,576)
Net earnings (loss)	**(217)**	(4,338)	**1,308**	84	**1,091**	(4,254)
Intersegment revenues	**988**	1,081	**—**	—	**988**	1,081

[1] *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

[2] *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between business segments.*

Downstream								Corporate and Eliminations[2]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2016	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
1,324	1,319	**2,301**	2,886	**5,995**	7,345	**9,620**	11,550	**(1,299)**	(1,425)	**13,312**	16,763
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(305)**	(432)
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(88)**	38
1,324	1,319	**2,301**	2,886	**5,995**	7,345	**9,620**	11,550	**(1,299)**	(1,425)	**12,919**	16,369
808	922	**1,770**	2,281	**5,188**	6,455	**7,766**	9,658	**(1,299)**	(1,425)	**7,356**	9,397
168	169	**241**	238	**535**	474	**944**	881	**—**	—	**2,724**	2,994
4	4	**43**	31	**13**	10	**60**	45	**247**	53	**544**	342
103	106	**102**	103	**342**	333	**547**	542	**87**	84	**2,462**	8,644
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**188**	447
—	—	**(3)**	(5)	**—**	—	**(3)**	(5)	**—**	—	**(1,634)**	(22)
(1)	(11)	**(10)**	1	**(176)**	(236)	**(187)**	(246)	**110**	(2)	**(27)**	(287)
1,082	1,190	**2,143**	2,649	**5,902**	7,036	**9,127**	10,875	**(855)**	(1,290)	**11,613**	21,515
242	129	**158**	237	**93**	309	**493**	675	**(444)**	(135)	**1,306**	(5,146)
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**15**	(5)
—	—	**—**	—	**—**	—	**—**	—	**13**	43	**13**	43
—	—	**—**	—	**—**	—	**—**	—	**12**	32	**17**	35
(1)	(1)	**(7)**	(6)	**(3)**	(3)	**(11)**	(10)	**(245)**	(146)	**(401)**	(298)
(1)	(1)	**(7)**	(6)	**(3)**	(3)	**(11)**	(10)	**(220)**	(71)	**(371)**	(220)
241	128	**151**	231	**90**	306	**482**	665	**(664)**	(206)	**950**	(5,371)
—	(17)	**—**	6	**—**	15	**—**	4	**99**	121	**(1)**	306
66	52	**41**	55	**33**	(106)	**140**	1	**(252)**	(71)	**29**	(1,827)
66	35	**41**	61	**33**	(91)	**140**	5	**(153)**	50	**28**	(1,521)
175	93	**110**	170	**57**	397	**342**	660	**(511)**	(256)	**922**	(3,850)
157	164	**154**	180	**—**	—	**311**	344	**—**	—	**1,299**	1,425

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[1]		Infrastructure and Marketing		Total	
Year ended December 31,	**2016**	2015	**2016**	2015	**2016**	2015
Expenditures on exploration and evaluation assets[2][3]	**46**	205	**—**	—	**46**	205
Expenditures on property, plant and equipment[2][3]	**826**	2,064	**54**	168	**880**	2,232
Investment in joint ventures	**140**	37	**36**	—	**176**	37
As at December 31,						
Exploration and evaluation assets	**1,066**	1,091	**—**	—	**1,066**	1,091
Developing and producing assets at cost	**44,790**	50,380	**—**	—	**44,790**	50,380
Accumulated depletion, depreciation, amortization and impairment	**(27,984)**	(31,298)	**—**	—	**(27,984)**	(31,298)
Other property, plant and equipment at cost	**—**	—	**140**	1,467	**140**	1,467
Accumulated depletion, depreciation and amortization	**—**	—	**(99)**	(576)	**(99)**	(576)
Total exploration and evaluation assets and property, plant and equipment, net	**17,872**	20,173	**41**	891	**17,913**	21,064
Total assets	**19,098**	21,103	**1,582**	1,699	**20,680**	22,802

(1) *Includes allocated depletion, depreciation, amortization and impairment related to assets in Infrastructure and Marketing, as these assets provide a service to Exploration and Production.*

(2) *Excludes capitalized costs related to asset retirement obligations and capitalized interest incurred during the year. Includes assets acquired through acquisitions.*

(3) *Capital expenditures in 2015 were revised to exclude capital expenditures incurred by the Husky-CNOOC Madura Ltd. joint venture which are classified as contribution to joint venture investing activities on the Company's Consolidated Statements of Cash Flows.*

Geographical Financial Information

($ millions)	Canada		United States	
Year ended December 31,	**2016**	2015	**2016**	2015
Gross revenues[1]	**5,993**	6,810	**6,512**	8,638
Royalties	**(261)**	(361)	**—**	—
Marketing and other	**(88)**	38	**—**	—
Revenue, net of royalties	**5,644**	6,487	**6,512**	8,638
As at December 31,				
Restricted Cash	**—**	—	**—**	—
Exploration and evaluation assets	**654**	690	**—**	—
Property, plant and equipment, net	**16,112**	19,005	**5,341**	5,139
Goodwill	**—**	—	**679**	700
Investment in joint ventures	**640**	—	**—**	—
Long-term income tax receivable	**232**	109	**—**	—
Other assets	**43**	83	**23**	23
Total non-current assets	**17,681**	19,887	**6,043**	5,862

(1) *Sales to external customers are based on the location of the seller.*

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
—	—	—	—	—	—	—	—	—	—	46	205
51	46	52	30	623	425	726	501	53	67	1,659	2,800
—	—	—	—	—	—	—	—	—	—	176	37
—	—	—	—	—	—	—	—	—	—	1,066	1,091
—	—	—	—	—	—	—	—	—	—	44,790	50,380
—	—	—	—	—	—	—	—	—	—	(27,984)	(31,298)
2,367	2,313	2,500	2,438	7,897	7,435	12,764	12,186	1,011	957	13,915	14,610
(1,363)	(1,260)	(1,344)	(1,245)	(2,556)	(2,296)	(5,263)	(4,801)	(766)	(681)	(6,128)	(6,058)
1,004	1,053	1,156	1,193	5,341	5,139	7,501	7,385	245	276	25,659	28,725
1,076	1,141	1,410	1,448	7,017	6,784	9,503	9,373	2,077	881	32,260	33,056

China		Other International		Total	
2016	2015	2016	2015	2016	2015
807	1,315	—	—	13,312	16,763
(44)	(71)	—	—	(305)	(432)
—	—	—	—	(88)	38
763	1,244	—	—	12,919	16,369
72	121	—	—	72	121
407	394	5	7	1,066	1,091
3,139	3,490	1	—	24,593	27,634
—	—	—	—	679	700
—	—	488	359	1,128	359
—	—	—	—	232	109
83	—	23	22	172	128
3,701	4,005	517	388	27,942	30,142

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

The consolidated financial statements have been prepared by management on a historical cost basis with some exceptions, as detailed in the accounting policies set out below in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements.

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 23, 2017 having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been restated to conform with current presentation.

b) Principles of Consolidation

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. Substantially all of the Company's Upstream activities are conducted jointly with third parties, and accordingly, the accounts reflect the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows from these activities. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements. A portion of the Company's activities relate to joint ventures (see Note 11), which are accounted for using the equity method.

c) Use of Estimates, Judgments and Assumptions

The timely preparation of the consolidated financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments and assumptions.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and on a prospective basis. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as the Company's operating environment changes. Specifically, amounts recorded for depletion, depreciation, amortization and impairment, asset retirement obligations, assets and liabilities measured at fair value, employee future benefits, income taxes and estimates and reserves and contingencies are based on estimates.

Management makes judgments regarding the application of IFRS for each accounting policy. Critical judgments that have the most significant effect on the amounts recognized in the consolidated financial statements include determination of technical feasibility and commercial viability, impairment assessments, the determination of cash generating units ("CGUs"), changes in reserve estimates, the determination of a joint arrangement, the designation of the Company's functional currency and the fair value of related party transactions.

Significant estimates, judgments and assumptions made by management in the preparation of these consolidated financial statements are outlined in detail in Note 3.

d) Functional and Presentation Currency

The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is presented in millions of Canadian dollars, except per share amounts and unless otherwise stated.

The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Note 3 Significant Accounting Policies

a) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with an original maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand and short-term deposits, and the Company has the ability to net settle, the excess is reported in bank operating loans.

Cash and cash equivalents held that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within 12 months, it is classified as a non-current asset.

b) Inventories

Crude oil, natural gas, refined petroleum products and sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead, operating costs, transportation and depreciation, depletion and amortization. Commodity inventories held for trading purposes are carried at fair value and measured at fair value less costs to sell based on Level 2 observable inputs, refer to policy Note 3 (m). Any changes in commodity inventory fair value are included as gains or losses in marketing and other in the consolidated statements of income, during the period of change. Previous inventory impairment provisions are reversed when there is a change in the condition that caused the impairment and the inventory remains on hand. Unrealized intersegment net earnings on inventory sales are eliminated.

c) Precious Metals

The Company uses precious metals in conjunction with a catalyst as part of the downstream upgrading and refining processes. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to production and operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in net earnings. Precious metals are included in other assets on the balance sheet.

d) Exploration and Evaluation Assets and Property, Plant and Equipment

i) Cost

Oil and gas properties and other property, plant and equipment are recorded at cost, including expenditures that are directly attributable to the purchase or development of an asset. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are included in the asset cost. Capitalization ceases when substantially all activities necessary to prepare the qualifying asset for its intended use are complete.

ii) Exploration and evaluation costs

The accounting treatment of costs incurred for oil and natural gas exploration, evaluation and development is determined by the classification of the underlying activities as either exploratory or developmental. The results from an exploration drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires determination of technical feasibility, commercial viability and industry experience. Exploration activities can fluctuate from year to year, due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in exploratory drilling and the degree of risk associated with drilling in particular areas. Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance.

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as exploration and evaluation assets. These costs include costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees. Pre-license costs and geological and geophysical costs associated with exploration activities are expensed in the period incurred. Costs directly associated with an exploration well are initially capitalized as an exploration and evaluation asset until the drilling of the well is complete and the results have been evaluated. If extractable hydrocarbons are found and are likely to be developed commercially, but are subject to further appraisal activity, which may include the drilling of wells, the costs continue to be carried as an exploration and evaluation asset while sufficient and continued progress is made in assessing the commercial viability of the hydrocarbons. Capitalized exploration and evaluation costs or assets are not depreciated and are carried forward until technical feasibility and commercial viability of the area is determined or the assets are determined to be impaired. Management determines technical feasibility and commercial viability when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, establishing commercial and technical feasibility and whether the asset can be developed using a proved development concept and has received internal approval. Upon the determination of technical feasibility and commercial viability, capitalized exploration and evaluation assets are then transferred to property, plant and equipment. All such carried costs are subject to technical, commercial and management review, as well as review for impairment indicators, at least every reporting period to confirm the continued intent to develop or otherwise extract value from the discovery. These costs are also tested for impairment when transferred to property, plant and equipment. Capitalized exploration and evaluation expenditures related to wells that do not find reserves, or where no future activity is planned, are expensed as exploration and evaluation expenses.

The application of the Company's accounting policy for exploration and evaluation costs 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. Judgments may change as new information becomes available.

iii) Development costs

Expenditures, including borrowing costs, on the construction, installation and completion of infrastructure facilities, such as platforms, pipelines and the drilling of development wells, including unsuccessful development or delineation wells, are capitalized as oil and gas properties. Costs incurred to operate and maintain wells and equipment to lift oil and gas to the surface are expensed as production and operating expenses.

iv) Other property, plant and equipment

Repair and maintenance costs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are capitalized as part of property, plant and equipment when incurred and are amortized over the estimated period of time to the anticipated date of the next turnaround.

v) Depletion, depreciation and amortization

Oil and gas properties are depleted on a unit-of-production basis over the proved developed reserves of the particular field, except in the case of assets whose useful life is shorter or longer than the lifetime of the proved developed reserves of that field, in which case the straight-line method or a unit-of-production method based on total proved plus probable reserves is applied. The unit-of-production rate for the depletion of oil and gas properties related to total proved plus probable reserves takes into account expenditures incurred to date together with sanctioned future development expenditures required to develop the field.

Oil and gas reserves are evaluated internally and audited by independent qualified reserve engineers. The estimation of reserves is an inherently complex process and involves the exercise of professional judgment. Estimates are based on projected future rates of production, estimated commodity prices, engineering data and the timing of future expenditures, all of which are subject to uncertainty. Changes in reserve estimates can have an impact on reported net earnings through revisions to depletion, depreciation and amortization expense, in addition to determining possible impairments and reversal of impairments of property, plant and equipment.

Net reserves represent the Company's undivided gross working interest in total reserves after deducting crown, freehold and overriding royalty interests. Assumptions reflect market and regulatory conditions, as applicable, as at the balance sheet date and could differ significantly from other points in time throughout the year or future periods. Changes in market and regulatory conditions and assumptions can materially impact the estimation of net reserves.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets, which range from five to forty-five years, less any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal, net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

Depletion, depreciation and amortization rates for all capitalized costs associated with the Company's activities are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves and estimated service lives.

vi) Finance Leases

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the lease property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

All other leases are accounted for as operating leases and the lease costs are expensed as incurred.

e) Joint Arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions. A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets.

For a joint operation, the consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of the joint arrangement. The Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases.

Joint ventures are accounted for using the equity method of accounting and recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the joint venture's net assets. The Company's consolidated financial statements include its share of the joint venture's profit or loss and other comprehensive income ("OCI") included in investment in joint ventures, until the date that joint control ceases.

Classification of a joint arrangement as either joint operation or joint venture requires judgment. Management's considerations include, but are not limited to, determining if the arrangement is structured through a separate vehicle and whether the legal form and contractual arrangements give the entity direct rights to the assets and obligations for the liabilities within the normal course of business. Other facts and circumstances are also assessed by management, including the entity's rights to the economic benefits of assets and its involvement and responsibility for settling liabilities associated with the arrangement.

f) Investments in Associates

An associate is an entity for which the Company has significant influence and thereby has the power to participate in the financial and operational decisions but does not control or jointly control the investee. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the investee's net assets. The Company's consolidated financial statements include its share of the investee's profit or loss and OCI until the date that significant influence ceases.

g) Business Combinations

Business combinations are accounted for using the acquisition method. Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case-by-case basis. If the acquisition meets the definition of a business combination, the assets and liabilities are recognized based on the contractual terms, economic conditions, the Company's operating and accounting policies and other factors that exist on the acquisition date, which is the date on which control is transferred to the Company. The identifiable assets and liabilities are measured at their fair values on the acquisition date with limited exceptions. Any additional consideration payable, contingent upon the occurrence of a future event, is recognized at fair value on the acquisition date; subsequent changes in the fair value of the liability are recognized in net earnings. Acquisition costs incurred are expensed and included in other – net in the consolidated statements of income.

h) Goodwill

Goodwill is the excess of the purchase price paid over the recognized amount of net assets acquired through business combinations, which is inherently imprecise as judgment is required in the determination of the fair value of assets and liabilities. Goodwill, which is not amortized, is assigned to appropriate CGUs or groups of CGUs. Goodwill is tested for impairment annually and when circumstances indicate that the carrying value may be impaired. Impairment losses are recognized in net earnings and are not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal.

i) Impairment and Reversals of Impairment on Non-Financial Assets

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at the end of each reporting period to determine whether there is an indication of impairment. If such indication exists, the recoverable amount is estimated.

Determining whether there are any indications of impairment or impairment reversals requires significant judgment of external factors, such as an extended decrease in prices or margins for oil and gas commodities or products, a significant decline in an asset's market value, a significant downward revision of estimated volumes, an upward revision of future development costs, a decline in the entity's market capitalization or significant changes in the technological, market, economic or legal environment that would have an adverse impact on the Company's CGUs. If any indication of impairment or impairment reversals exist, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") for an individual asset or CGU. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, which is the smallest identifiable group of assets, liabilities and associated goodwill that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. Determination of the Company's CGUs is subject to management's judgment.

FVLCS is the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS is generally determined as the net present value of the estimated future cash flows expected to arise from a CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted using a rate that would be applied by a market participant to arrive at a net present value of the CGU.

VIU is the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account sanctioned future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, forecasted crack spreads, growth rate, discount rate and, in the case of oil and gas properties, expected production volumes. Expected production volumes take into account assessments of field reservoir performance and include expectations about proved and probable volumes and where applicable economically recoverable resources associated with interests in certain Husky properties which are risk-weighted utilizing geological, production, recovery, market price and economic projections. Either the cash flow estimates or the discount rate is risk-adjusted to reflect local conditions as appropriate.

Given that the calculations for recoverable amounts require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and in the case of oil and gas properties, expected production volumes, it is possible that the assumptions may change, which may impact the estimated life of the CGU and may require a material adjustment to the carrying value of goodwill and non-financial assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized with respect to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the CGU or group of CGUs on a pro rata basis. Impairment losses are recognized in depletion, depreciation, amortization and impairment in the consolidated statements of income (loss).

Impairment losses recognized for other assets in prior years are assessed at the end of each reporting period for indications that the impairment has decreased or no longer exists. An impairment loss is reversed only to the extent that the carrying amount of the asset or CGU does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

j) Asset Retirement Obligations ("ARO")

A liability is recognized for future legal or constructive retirement obligations associated with the Company's assets. The Company has significant obligations to remove tangible assets and restore land after operations cease and the Company retires or relinquishes the asset. The retirement of Upstream and Downstream assets consists primarily of plugging and abandoning wells, abandoning surface and subsea plant and equipment and facilities and restoring land to a state required by regulation or contract. The amount recognized is the net present value of the estimated future expenditures determined in accordance with local conditions, current technology and current regulatory requirements. The obligation is calculated using the current estimated costs to retire the asset inflated to the estimated retirement date and then discounted using a credit-adjusted risk-free discount rate. The liability is recorded in the period in which an obligation arises with a corresponding increase to the carrying value of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an expense recognized in finance expenses. The costs capitalized to the related assets are amortized in a manner consistent with the depletion, depreciation and amortization of the underlying assets. Actual retirement expenditures are charged against the accumulated liability as incurred.

Liabilities for ARO are adjusted every reporting period for changes in estimates. These adjustments are accounted for as a change in the corresponding capitalized cost, except where a reduction in the provision is greater than the undepreciated capitalized cost of the related assets, in which case the capitalized cost is reduced to nil and the remaining adjustment is recognized in net earnings. Changes to the amount of capitalized costs will result in an adjustment to future depletion, depreciation and amortization, and to finance expenses.

Estimating the ARO requires significant judgment as restoration technologies and costs are constantly changing, as are regulatory, political, environmental and safety considerations. Inherent in the calculation of the ARO are numerous assumptions including the ultimate settlement amounts, future third-party pricing, inflation factors, risk-free discount rates, credit risk, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in material changes to the ARO liability. Adjustments to the estimated amounts and timing of future ARO cash flows are a regular occurrence in light of the significant judgments and estimates involved.

k) Legal and Other Contingent Matters

Provisions and liabilities for legal and other contingent matters are recognized in the period when the circumstance becomes probable that a future cash outflow resulting from past operations or events will occur and the amount of the cash outflow can be reasonably estimated. The timing of recognition and measurement of the provision requires the application of judgment to existing facts and circumstances, which can be subject to change, and the carrying amounts of provisions and liabilities are reviewed regularly and adjusted accordingly. The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can be reasonably estimated. When a loss is recognized, it is charged to net earnings. The Company continually monitors known and potential contingent matters and makes appropriate disclosure and provisions when warranted by the circumstances present.

l) Share Capital

Preferred shares are classified as equity since they are cancellable and redeemable only at the Company's option and dividends are discretionary and payable only if declared by the Board of Directors. Incremental costs directly attributable to the issuance of shares and stock options are recognized as a deduction from equity, net of tax. Common share dividends are paid out in common shares, or in cash, and preferred share dividends are paid in cash. Both common and preferred share dividends are recognized as distributions within equity.

m) Financial Instruments

Financial instruments are any contracts that give rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are initially recognized at fair value, and subsequently measured based on classification in one of the following categories: loans and receivables, held to maturity investments, other financial liabilities, fair value through profit or loss ("FVTPL") or available-for-sale ("AFS") financial assets.

Financial instruments classified as FVTPL or AFS are measured at fair value at each reporting date; any transaction costs associated with these types of instruments are expensed as incurred. Unrealized gains and losses on AFS financial assets are recognized in OCI (see policy note o) and transferred to net earnings when the asset is derecognized. Unrealized gains and losses on FVTPL financial instruments related to trading activities are recognized in marketing and other in the consolidated statements of income, and unrealized gains and losses on all other FVTPL financial instruments are recognized in other – net.

Financial instruments classified as loans or receivables, held to maturity investments and other financial liabilities are initially measured at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs that are directly attributable to the acquisition or issue of a financial instrument are measured at amortized cost and added to the fair value initially recognized.

Financial instruments subsequently revalued at fair value are further categorized using a three-level hierarchy that reflects the significance of the inputs used in determining fair value. Level 1 fair value is determined by reference to quoted prices in active markets for identical assets and liabilities. Level 2 fair value is based on inputs that are independently observable for similar assets or liabilities. Level 3 fair value is not based on independently observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value.

n) Derivative Instruments and Hedging Activities

Derivatives are financial instruments for which the fair value changes in response to market risks, require little or no initial investment and are settled at a future date. Derivative instruments are utilized by the Company to manage various market risks including volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may enter into swap and other derivative transactions to hedge or mitigate the Company's commercial risk, including derivatives that reduce risks that arise in the ordinary course of the Company's business. The Company may choose to apply hedge accounting to derivative instruments.

The fair values of derivatives are determined using valuation models that require assumptions concerning the amount and timing of future cash flows and discount rates. These estimates are also subject to change with fluctuations in commodity prices, interest rates, foreign currency exchange rates and estimates of non-performance. The actual settlement of a derivative instrument could differ materially from the fair value recorded and could impact future results.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

The Company may enter into commodity price contracts in order to offset fixed or floating prices with market rates to manage exposures to fluctuations in commodity prices. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The related inventory is measured at fair value based on exit prices. Gains and losses from these derivative contracts, which are not designated as effective hedging instruments, are recognized in revenues or purchases of crude oil and products and are initially recorded at settlement date. Derivative instruments that have been designated as effective hedging instruments are further classified as either fair value or cash flow hedges (see "Hedging Activities").

ii) Embedded Derivatives

Derivatives embedded in a host contract are recorded separately when the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract and the host contract is not measured at FVTPL. The definition of an embedded derivative is the same as freestanding derivatives. Embedded derivatives are measured at fair value with gains and losses recognized in net earnings.

iii) Hedging Activities

At the inception of a derivative transaction, if the Company elects to use hedge accounting, formal designation and documentation is required. The documentation must include: identification of the hedged item or transaction, the hedging instrument, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the Company will assess the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item.

A hedge is assessed at inception and at the end of each reporting period to ensure that it is highly effective in offsetting changes in fair values or cash flows of the hedged item. For a fair value hedge, the gain or loss from remeasuring the hedging instrument at fair value is recognized immediately in net earnings with the offsetting gain or loss on the hedged item. When fair value hedge accounting is discontinued, the carrying amount of the hedging instrument is deferred and amortized to net earnings over the remaining maturity of the hedged item.

For a cash flow hedge, the effective portion of the gain or loss is recorded in OCI. Any hedge or portion of a hedge that is ineffective is immediately recognized in net earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting. Any gain or loss on the hedging instrument resulting from the discontinuation of a cash flow hedge is deferred in OCI until the forecasted transaction date. If the forecasted transaction date is no longer expected to occur, the gain or loss is recognized in net earnings in the period of discontinuation.

A net investment hedge of a foreign operation is accounted for similarly to a cash flow hedge. The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax, and are limited to the translation gain or loss on the net investment.

o) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI is comprised of the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, the unrealized gains and losses on AFS financial assets, the exchange gains and losses arising from the translation of foreign operations with a functional currency that is not Canadian dollars and the actuarial gains and losses on defined benefit pension plans. Amounts included in OCI are shown net of tax. Other reserves is an equity category comprised of the cumulative amounts of OCI, relating to foreign currency translation and hedging.

p) Impairment of Financial Assets

A financial asset is assessed at the end of each reporting period to determine whether it is impaired, based on objective evidence indicating that one or more events have had a negative effect on the estimated future cash flows of that asset. Objective evidence used by the Company to assess impairment of financial assets includes quoted market prices for similar financial assets and historical collection rates for loans and receivables.

An impairment loss with respect to a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the net present value of the estimated future cash flows discounted at the original effective interest rate. A revaluation with respect to an AFS financial asset is calculated by reference to its fair value and any amounts in OCI are transferred to net earnings.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

q) Pensions and Other Post-employment Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides two defined contribution pension plans (401(k)) and one other post-retirement benefits plan.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the defined benefit pension plans is determined using the projected unit credit funding method. Actuarial gains and losses are recognized in retained earnings as incurred.

The defined benefit asset or liability is comprised of the fair value of plan assets from which the obligations are to be settled and the present value of the defined benefit obligation. Plan assets are measured at fair value based on the closing bid price when there is a quoted price in an active market. Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the Company's creditors. The value of any defined benefit asset is restricted to the sum of any past service costs and the present value of refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using the year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Post-retirement medical benefits are also provided to qualifying retirees. In some cases the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans there is no funding of the benefits before retirement. These plans are recognized on the same basis as described above for the defined benefit pension plan.

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of assumptions that affect the expected future benefit payments. The valuation of these plans is prepared by an independent actuary engaged by the Company. These assumptions include, but are not limited to, the estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The rate of return on pension plan assets is based on a projection of real long-term bond yields and an equity risk premium, which are combined with local inflation assumptions and applied to the actual asset mix of each plan. The amount of the expected return on plan assets is calculated using the expected rate of return for the year and the fair value of assets at the beginning of the year. Future salary increases are based on expected future inflation rates for the individual countries.

r) Income Taxes

Current income tax is recognized in net earnings in the period unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

Deferred tax is measured using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax assets and liabilities are recognized at expected tax rates in effect in the year when the asset is expected to be realized or the liability settled, based on tax rates and tax laws that have been enacted or substantively enacted at the reporting date. 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 unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. Estimates that require significant judgments are also made with respect to the timing of temporary difference reversals, the realizability of tax assets and in circumstances where the transaction and calculations for which the ultimate tax determination are uncertain. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

s) Asset Exchange Transactions

Asset exchange transactions are measured at cost if the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Otherwise, asset exchange transactions are measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up. Gains and losses are recorded in other – net in the consolidated statements of income in the period they occur.

t) Revenue Recognition

Revenue from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided.

Under take or pay contracts, the Company makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. If a buyer has a right to get a "make-up" delivery at a later date, revenue is deferred and recognized only when the product is delivered or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognized when the take-or-pay penalty is triggered.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Crude oil and natural gas sold below or above the Company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at cost with a corresponding decrease to production and operating expense, while overlifts are recorded as a payable at fair value with a corresponding increase to production and operating expense.

Physical exchanges of inventory are reported on a net basis for swaps of similar items, as are sales and purchases made with a common counterparty as part of an arrangement similar to a physical exchange.

Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

u) Foreign Currency

Functional currency is the currency of the primary economic environment in which the Company and its subsidiaries operate and is normally the currency in which the entity primarily generates and expends cash. The financial statements of Husky's subsidiaries are translated into Canadian dollars, which is the presentation and functional currency of the Company. The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the foreign exchange rate at the balance sheet date, while revenues and expenses of such subsidiaries are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are included in OCI.

The Company's transactions in foreign currencies are translated to the appropriate functional currency at the foreign exchange rate on the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date and differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the dates of the transactions.

v) Share-based Payments

In accordance with the Company's stock option plan, stock options to acquire common shares may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted. Compensation expense is recorded in net earnings as part of selling, general and administrative expenses.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for the stock options is accrued over their vesting period and measured at fair value using the Black-Scholes option pricing model. The liability is revalued each reporting period until it is settled to reflect changes in the fair value of the options. The net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

The Company's Performance Share Unit Plan provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSU") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash payment is contingent on the Company's total shareholder return relative to a peer group of companies and achieving a return on capital in use ("ROCIU") target. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. A liability for expected cash payments is accrued over the vesting period of the PSUs and is revalued at each reporting date based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount.

w) Earnings per Share

The number of basic common shares outstanding is the weighted average number of common shares outstanding for each period. Shares issued during the period are included in the weighted average number of shares from the date consideration is receivable. The calculation of basic earnings per common share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding.

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money stock options would be used to buy back common shares at the average market price for the period. The calculation of diluted earnings per share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding adjusted for the effects of all potential dilutive common share issuances, which are comprised of common shares issuable upon exercise of stock options granted to employees. Stock options granted to employees provide the holder with the ability to settle in cash or equity. For the purposes of the diluted earnings per share calculation, the Company must adjust the numerator for the more dilutive effect of cash-settlement versus equity-settlement despite how the stock options are accounted for in net earnings. As a result, net earnings reported based on accounting of cash-settled stock options may be adjusted for the results of equity-settlements for the purposes of determining the numerator for the diluted earnings per share calculation.

x) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. If a grant is received but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an expense item, it is recognized as income in the period in which the costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and recognized in net earnings in equal amounts over the expected useful life of the related asset through lower depletion, depreciation and amortization.

y) Related Party Judgments and Estimates

The Company entered into transactions and agreements in the normal course of business with certain related parties, joint arrangements and associates. These transactions are on terms equivalent to those that prevail in arm's length transactions, unless otherwise noted. Proceeds for disposition of assets to related parties are recognized at fair value, based on discounted cash flow forecast from those assets. Independent opinions of the fair value may be obtained. Changes in the assumptions used to determine these fair values may result in a material difference in the proceeds and any gain or loss on disposition. See Note 25.

z) Recent Accounting Standards

The Company has not early adopted any standard, interpretation or amendment that has been issued but is not yet effective.

Leases

In January 2016, the IASB issued IFRS 16 Leases, which replaces the current IFRS guidance on leases. Under the current guidance, lessees are required to determine if the lease is a finance or operating lease, based on specified criteria. Finance leases are recognized on the balance sheet, while operating leases are recognized in the Consolidated Statements of Income (Loss) when the expense is incurred. Under IFRS 16, lessees must recognize a lease liability and a right-of-use asset for virtually all lease contracts. The recognition of the present value of minimum lease payments for certain contracts currently classified as operating leases will result in increases to assets, liabilities, depletion, depreciation and amortization, and finance expense, and a decrease to production, operating and transportation expense upon implementation. An optional exemption to not recognize certain short-term leases and leases of low value can be applied by lessees. For lessors, the accounting remains essentially unchanged. The standard will be effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted, provided IFRS 15 Revenue from Contracts with Customers, has been applied, or is applied at the same date as IFRS 16. The Company is currently evaluating the dollar impact of adopting IFRS 16 on the Company's consolidated financial statements.

Revenue from Contracts with Customers

In September 2015, the IASB published an amendment to IFRS 15, deferring the effective date of the standard by one year to annual periods beginning on or after January 1, 2018. IFRS 15 replaces existing revenue recognition guidance with a single comprehensive accounting model. 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. Early adoption is permitted. The Company is currently in the scoping phase of implementation. Adopting IFRS 15 is not expected to have a material impact on the Company's consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9, "Financial Instruments" to replace IAS 39, which provides a single model for classification and measurement 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 instruments. For 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. IFRS 9 includes a new, forward-looking 'expected loss' impairment model that will result in more timely recognition of expected credit losses. In addition, IFRS 9 provides a substantially-reformed approach to hedge accounting. The standard is effective for annual periods beginning on or after January 1, 2018, with required retrospective application and early adoption permitted. The Company intends to retrospectively adopt the standard on January 1, 2018. The adoption of IFRS 9 is not expected to have a material impact on the Company's consolidated financial statements.

Amendments to IAS 7 Statement of Cash Flows

In January 2016, the IASB issued amendments to IAS 7 to be applied prospectively for annual periods beginning on or after January 1, 2017 with early adoption permitted. The amendments require disclosure of information enabling users of financial statements to evaluate changes in liabilities arising from financing activities. The adoption of the IAS 7 amendments will require additional disclosure in the Company's consolidated financial statements.

Amendments to IFRS 2 Share-based Payment

In June 2016, the IASB issued amendments to IFRS 2 to be applied prospectively for annual periods beginning on or after January 1, 2018 with early adoption permitted. The amendments clarify how to account for certain types of share-based payment transactions. The adoption of the amendments is not expected to have a material impact on the Company's consolidated financial statements.

aa) Change in Accounting Policy

The Company has applied the following amendments to accounting standards issued by the IASB for the first time for the annual reporting period commencing January 1, 2016:

Amendments to IAS 1 Presentation of Financial Statements

The amendments clarify guidance on materiality and aggregation, use of subtotals, aggregation and disaggregation of financial statement line items, the order of the notes to the financial statements and disclosure of significant accounting policies. The adoption of this amended standard had no material impact on the Company's consolidated financial statements.

Amendments to IFRS 7 Financial Instrument: Disclosures

The amendments clarify:

- Whether a servicing contract is continuing involvement in a transferred asset for the purpose of determining the disclosures required; and
- The applicability of the amendments to IFRS 7 on offsetting disclosures to condensed interim financial statements.

The adoption of this amended standard had no material impact on the Company's consolidated financial statements.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2016 included $271 million of cash (December 31, 2015 – $68 million) and $1,048 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2015 – $2 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2016**	December 31, 2015
Trade receivables	**1,019**	962
Allowance for doubtful accounts	**(32)**	(31)
Derivatives due within one year	**9**	59
Other	**40**	24
End of year	**1,036**	1,014

Note 6 Inventories

Inventories

($ millions)	**December 31, 2016**	December 31, 2015
Crude oil, natural gas and sulphur	**523**	536
Refined petroleum products	**433**	257
Trading inventories measured at fair value less costs to sell	**399**	257
Materials, supplies and other	**203**	197
End of year	**1,558**	1,247

Impairment of inventory to net realizable value for the year ended December 31, 2016 was $9 million (December 31, 2015 – $22 million).

Trading inventories measured at fair value less costs to sell consist of natural gas inventories and crude oil inventories. The fair value measurement incorporates exit commodity prices and adjustments for quality and location. Refer to Note 24.

Note 7 Restricted Cash

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in the Asia Pacific Region. As at December 31, 2016, the Company had deposited funds of $156 million (2015 – $121 million) into the restricted cash account, of which $84 million relates to the Wenchang field and have been classified as current and the remaining balance of $72 million have been classified as non-current.

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2016**	2015
Beginning of year	**1,091**	1,149
Additions	**95**	227
Disposals	**(6)**	—
Transfers to oil and gas properties *(note 9)*	**(18)**	(97)
Expensed exploration expenditures previously capitalized	**(86)**	(242)
Exchange adjustments	**(10)**	54
End of year	**1,066**	1,091

During 2016, the $86 million in expensed exploration expenditures previously capitalized primarily relates to two unsuccessful exploration wells in the Atlantic Region and a decision by management to not pursue further evaluation of certain Oil Sands assets at this time, due to them being uneconomic under current and long term commodity prices.

The following exploration and evaluation expenses for the years ended December 31, 2016 and 2015 relate to activities associated with the exploration for and evaluation of crude oil and natural gas resources and were recorded in the Upstream Exploration and Production business.

Exploration and Evaluation Expense Summary

($ millions)	**2016**	2015
Seismic, geological and geophysical	**78**	103
Expensed drilling	**66**	297
Expensed land	**44**	47
	188	447

During 2015, $48 million of the $297 million in total expensed drilling was recorded as an exploration and evaluation expense due to unfulfilled work commitment penalties in Western Canada resulting from management's plan to withdraw from further exploration and evaluation due to lower estimated short and long-term crude oil and natural gas prices.

Note 9 Property, Plant and Equipment

Property, Plant and Equipment *($ millions)*	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
December 31, 2014	47,974	1,296	2,274	6,561	2,632	60,737
Additions	2,128	173	46	452	76	2,875
Acquisitions	57	—	—	—	—	57
Transfers from exploration and evaluation *(note 8)*	97	—	—	—	—	97
Intersegment transfers	6	(6)	—	—	—	—
Changes in asset retirement obligations *(note 16)*	(107)	—	(7)	(5)	(18)	(137)
Disposals and derecognition	(487)	—	—	(24)	(4)	(515)
Exchange adjustments	720	2	—	1,152	2	1,876
December 31, 2015	50,388	1,465	2,313	8,136	2,688	64,990
Additions	**818**	**55**	**51**	**712**	**61**	**1,697**
Acquisitions	**67**	**—**	**—**	**—**	**—**	**67**
Transfers from exploration and evaluation *(note 8)*	**18**	**—**	**—**	**—**	**—**	**18**
Changes in asset retirement obligations *(note 16)*	**231**	**—**	**3**	**11**	**9**	**254**
Disposals and derecognition	**(6,590)**	**(1,383)**	**—**	**—**	**(3)**	**(7,976)**
Exchange adjustments	**(131)**	**—**	**—**	**(214)**	**—**	**(345)**
December 31, 2016	**44,801**	**137**	**2,367**	**8,645**	**2,755**	**58,705**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2014	(23,687)	(527)	(1,154)	(1,988)	(1,394)	(28,750)
Depletion, depreciation, amortization and impairment	(7,811)	(48)	(106)	(365)	(154)	(8,484)
Intersegment transfers	(2)	2	—	—	—	—
Disposals and derecognition	370	—	—	18	2	390
Exchange adjustments	(170)	(1)	—	(341)	—	(512)
December 31, 2015	(31,300)	(574)	(1,260)	(2,676)	(1,546)	(37,356)
Depletion, depreciation, amortization and impairment	**(1,806)**	**(23)**	**(103)**	**(380)**	**(150)**	**(2,462)**
Disposals and derecognition	**5,082**	**501**	**—**	**13**	**4**	**5,600**
Exchange adjustments	**38**	**—**	**—**	**68**	**—**	**106**
December 31, 2016	**(27,986)**	**(96)**	**(1,363)**	**(2,975)**	**(1,692)**	**(34,112)**
Net book value						
December 31, 2015	19,088	891	1,053	5,460	1,142	27,634
December 31, 2016	**16,815**	**41**	**1,004**	**5,670**	**1,063**	**24,593**

Included in depletion, depreciation, amortization and impairment expense for the year ended December 31, 2016 is a pre-tax net impairment reversal of $261 million (2015 - pre-tax impairment expense of $5,021 million) on crude oil and natural gas assets located in Western Canada in the Upstream Exploration and Production segment.

Under IFRS, any asset impairment that is recorded must be reversed to its original value less any associated depletion, depreciation and amortization expenses should there be indicators that the recoverable amount of the asset has increased in value since the time of recognizing the initial impairment. At December 31, 2016, a $336 million pre-tax recovery of impairment was recognized on the Rainbow CGU in the Upstream Exploration and Production segment, due to acceleration of production profiles and revised operational economics, based on recent production performance and reinforced by market transactions. The recoverable amount for the Rainbow CGU as at December 31, 2016 is $604 million (2015 - $346 million). The recoverable amount of the CGU was estimated based on FVLCS using estimated discounted cash flows based on proved plus probable reserves and a pre-tax discount rate of 11 percent (Level 3). The Company did not identify any further impairment reversal indicators across the other CGUs.

The pre-tax impairment expense of $58 million (2015 - $101 million) for the year ended December 31, 2016 related to crude oil and natural gas assets located in the Provost West CGU. The impairment charge within the Upstream Exploration and Production segment, reflected in the fourth quarter of 2016, was the result of negative technical reserve revisions based on recent production performance and reinforced by market transactions. The recoverable amount for the Provost West CGU as at December 31, 2016 is $10 million (2015 - $91 million). The recoverable amount is based on FVLCS using estimated discounted cash flows based on proved plus probable reserves and a pre-tax discount rate of 11 percent (Level 3). In addition, an impairment of $17 million was recorded on the Northern CGU prior to sale (Level 3). The Company did not identify any further impairment indicators across the other CGUs.

The recoverable amount is sensitive to commodity price, discount rate, production volumes, operating costs, royalty rates and future capital expenditures. Commodity prices are based on market indicators at the end of the period. Management's long-term assumptions are benchmarked against the forward price curve and external firms. The prices used are consistent with those used by the Company in determining the recoverable amount of property, plant and equipment. The discount rate for FVLCS represents the rate a market participant would apply to the cash flows in a market transaction. Production volumes, operating costs and future capital expenditures are based on management's best estimates of future costs included in the long range plan approved by the Board of Directors.

A change in the discount rate or forward price over the life of the reserves will result in the following impact on the Provost West and Rainbow CGUs:

	Discount Rate		Commodity Price	
($ millions)	1% Increase in Discount Rate	1% Decrease in Discount Rate	5% Increase in Forward Price	5% Decrease in Forward Price
Impairment of PP&E, Provost West - Increase (Decrease)	2	(2)	(12)	11
Impairment Reversal of PP&E, Rainbow - Increase (Decrease)	(25)	26	95	(95)

The table below summarizes the forecasted prices used in determining the recoverable amounts in the above CGUs:

	WTI ($US/bbl)	Brent ($US/bbl)	Edmonton Light ($CDN/bbl)	AECO ($CDN/mcf)	Foreign Exchange ($US/$CDN)
2017	55.00	60.00	64.94	3.06	0.770
2018	60.00	70.00	74.88	3.12	0.800
2019	65.00	71.40	76.37	3.18	0.800
2020	70.00	72.83	77.90	3.25	0.800
2021	71.40	74.28	79.46	3.31	0.800
2022	72.83	75.77	81.05	3.38	0.800
2023[(1)]	74.28	77.29	82.67	3.45	0.800

(1) *Prices are escalated at 2 percent thereafter.*

Costs of property, plant and equipment, including major development projects, not subject to depletion, depreciation and amortization as at December 31, 2016 were $1.8 billion (December 31, 2015 – $3.0 billion) including undeveloped land assets of $95 million as at December 31, 2016 (December 31, 2015 – $68 million).

The net book values of assets held under finance lease within property, plant and equipment are as follows:

Assets Under Finance Lease *($ millions)*	Refining	Oil and Gas Properties	Total
December 31, 2015	26	255	281
December 31, 2016	**24**	**255**	**279**

Assets Dispositions

On May 25, 2016, the Company completed the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production for gross proceeds of $165 million, resulting in a pre-tax gain of $163 million and an after-tax gain of $119 million.

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The Company also recognized an investment of $621 million for its 35 percent retained interest. This transaction resulted in a change of control and the recognition of a pre-tax gain of $1.44 billion and an after-tax gain of $1.32 billion. The assets and related liabilities were recorded in the Upstream Infrastructure and Marketing segment. The assets are held by a newly formed limited partnership, Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holding Ltd. ("PAH") owns 48.75 percent and Cheung Kong Infrastructure Holdings Ltd. ("CKI") owns 16.25 percent. Husky remains operator of the assets.

During 2016, the Company completed the sale of approximately 30,200 boe/day of legacy crude oil and gas assets in Western Canada for gross proceeds of $1.12 billion. The Company recognized a pre-tax gain of $35 million and an after-tax gain of $25 million.

Note 10 Goodwill

Goodwill

($ millions)	**December 31, 2016**	December 31, 2015
Beginning of year	**700**	746
Exchange adjustments	**(21)**	114
Impairment	**—**	(160)
End of year	**679**	700

As at December 31, 2016, the Company's goodwill balance related entirely to the Lima Refinery. For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using the higher of FVLCS and VIU methodology based on cash flows expected over a 50-year period and discounted using a pre-tax discount rate of 8 percent (2015 – 8 percent).

The value-in-use calculation for the Lima Refinery CGU is sensitive to changes in discount rate, forecasted crack spreads and growth rate. The discount rate is derived from the Company's post-tax weighted average cost of capital with appropriate adjustments made to reflect the risks specific to the refinery. Forecasted crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and are consistent with crack spreads used in the Company's long range plan.

Cash flow projections for the initial 10-year period are based on long range plan future cash flows and inflated by a 2 percent long-term growth rate for the remaining 40-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2 percent (2015 – 2 percent). As at December 31, 2016, the recoverable amount exceeded the carrying amount and no impairment was identified.

The Company used the market capitalization and comparative market multiplier to corroborate discounted cash flow results.

Note 11 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

The Company holds a 50 percent ownership interest in BP-Husky Refining LLC, which owns and operates the BP-Husky Toledo Refinery in Ohio. On March 31, 2008, the Company completed a transaction with BP whereby BP contributed the BP-Husky Toledo Refinery plus inventories and other related net assets and the Company contributed U.S. $250 million in cash and a contribution payable of U.S. $2.6 billion.

The Company's proportionate share of the contribution payable included in the consolidated balance sheets is as follows:

Contribution Payable

($ millions)	**December 31, 2016**	December 31, 2015
Beginning of year	**348**	1,528
Accretion *(note 21)*	**6**	16
Paid	**(193)**	(1,363)
Foreign exchange	**(15)**	167
End of year	**146**	348
Expected to be incurred within 1 year	**146**	210
Expected to be incurred beyond 1 year	**—**	138

The Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, U.S. $1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed U.S. $1 billion to each of the joint arrangement partners, which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately U.S. $110 million (CDN $146 million) will be paid by way of funding all capital contributions of the BP-Husky Refining LLC joint operation during 2017 and repaying the remaining balance by the end of 2017.

Summarized below is the Company's proportionate share of operating results and financial position in the BP-Husky Refining LLC joint operation that have been included in the consolidated statements of income (loss) and the consolidated balance sheets in U.S. Refining and Marketing in the Downstream segment:

Results of Operations

($ millions)	**2016**	2015
Revenues	**1,521**	1,959
Expenses	**(1,570)**	(1,826)
Proportionate share of net earnings (loss)	**(49)**	133

Balance Sheets

($ millions)	**December 31, 2016**	December 31, 2015
Current assets	**395**	469
Non-current assets	**2,446**	2,405
Current liabilities	**(324)**	(367)
Non-current liabilities	**(535)**	(681)
Proportionate share of net assets	**1,982**	1,826

Sunrise Oil Sands Partnership

The Company holds a 50 percent interest in the Sunrise Oil Sands Partnership, which is engaged in operating an oil sands project in Northern Alberta.

Summarized below is the Company's proportionate share of operating results and financial position in the Sunrise Oil Sands Partnership that have been included in the consolidated statements of income (loss) and the consolidated balance sheets in Exploration and Production in the Upstream segment:

Results of Operations

($ millions)	2016	2015
Revenues	106	17
Expenses	(220)	(160)
Financial items	(28)	(28)
Proportionate share of net loss	(142)	(171)

Balance Sheets

($ millions)	December 31, 2016	December 31, 2015
Current assets	57	28
Non-current assets	3,147	3,161
Current liabilities	(98)	(104)
Non-current liabilities	(274)	(248)
Proportionate share of net assets	2,832	2,837

Joint Venture

Husky-CNOOC Madura Ltd.

The Company currently holds 40 percent joint control in Husky-CNOOC Madura Ltd., which is engaged in exploring for oil and gas resources in Indonesia with a fiscal year end of December 31. Results of the joint venture are included in the consolidated statements of income (loss) in Exploration and Production in the Upstream segment.

Summarized below is the financial information for Husky-CNOOC Madura Ltd. accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	2016	2015
Revenues	—	—
Expenses	(32)	(25)
Net loss	(32)	(25)
Share of equity investment (percent)	40%	40%
Proportionate share of equity investment	(1)	(5)

Balance Sheets

($ millions, except share of equity investment)	December 31, 2016	December 31, 2015
Current assets[(1)]	67	79
Non-current assets	1,111	780
Current liabilities	(134)	(46)
Non-current liabilities	(836)	(559)
Net assets	208	254
Share of net assets (percent)	40%	40%
Carrying amount in balance sheet	488	359

[(1)] *Current assets include cash and cash equivalents of $7 million (2015 – $34 million).*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 40 percent joint control of the expenses and net assets of Husky-CNOOC Madura Ltd. due to differences in the accounting policies of the joint venture and the Company and non-current liabilities of the joint venture which are not included in the Company's carrying amount of net assets due to equity accounting.

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan. The assets are held by a newly-formed limited partnership, HMLP, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. Results of the joint venture are included in the Upstream Infrastructure and Marketing segment.

Summarized below is the financial information for HMLP accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2016**
Revenues	**138**
Expenses[(1)]	**(97)**
Net income	**41**
Share of equity investment (percent)	**35%**
Proportionate share of equity investment	**16**

Balance Sheet

($ millions, except share of net assets)	**December 31, 2016**
Current assets[(2)]	**55**
Non-current assets	**2,403**
Current liabilities	**(44)**
Non-current liabilities	**(590)**
Net assets	**1,824**
Share of net assets (percent)	**35%**
Carrying amount in balance sheet	**640**

(1) *As at December 31, 2016, total gross costs incurred in response to the pipeline leak were approximately $107 million, for which $88 million has been recovered through insurance proceeds. Both the spill costs and insurance recoveries have been incurred by HMLP.*

(2) *Current assets include cash and cash equivalents of $23 million.*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 35 percent joint control of the net income and net assets of HMLP due to the potential fluctuation in the partnership profit structure.

Note 12 Other Assets

Other Assets

($ millions)	December 31, 2016	December 31, 2015
Long-term receivables	**117**	33
Leasehold incentives	**13**	34
Precious metals	**23**	23
Other	**19**	38
End of period	**172**	128

Note 13 Bank Operating Loans

At December 31, 2016, the Company had unsecured short-term borrowing lines of credit with banks totalling $670 million (December 31, 2015 – $645 million) and letters of credit under these lines of credit totalling $378 million (December 31, 2015 – $216 million). As at December 31, 2016, bank operating loans were nil (December 31, 2015 – nil). Interest payable is based on Bankers' Acceptance, U.S. LIBOR or prime rates.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million (December 31, 2015 - $10 million) available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million (December 31, 2015 - $5 million). As at December 31, 2016, there was no balance outstanding under this credit facility (December 31, 2015 – nil).

Note 14 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	December 31, 2016	December 31, 2015
Trade payables	**762**	636
Accrued liabilities	**1,275**	1,498
Dividend payable *(note 19)*	**9**	296
Stock-based compensation	**17**	6
Derivatives due within one year	**61**	18
Other	**102**	73
End of year	**2,226**	2,527

Note 15 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2016**	December 31, 2015
Commercial paper(1)	**200**	720

(1) *The commercial paper is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2016 was 0.93 percent per annum (December 31, 2015 – 0.81 percent).*

Long-term Debt *($ millions)*	Maturity	Canadian $ Amount **December 31, 2016**	Canadian $ Amount December 31, 2015	U.S. $ Denominated **December 31, 2016**	U.S. $ Denominated December 31, 2015
Long-term debt					
Syndicated Credit Facility	2018	**—**	499	**—**	—
6.20% notes(1)(5)	2017	**—**	415	**—**	300
6.15% notes(1)(4)	2019	**403**	415	**300**	300
7.25% notes(1)(5)	2019	**1,007**	1,038	**750**	750
5.00% notes(6)	2020	**400**	400	**—**	—
3.95% notes(1)(5)	2022	**671**	692	**500**	500
4.00% notes (1)(5)	2024	**1,007**	1,038	**750**	750
3.55% notes(6)	2025	**750**	750	**—**	—
6.80% notes(1)(5)	2037	**519**	535	**387**	387
Debt issue costs(2)		**(23)**	(27)	**—**	—
Unwound interest rate swaps *(note 24)*		**2**	4	**—**	—
Long-term debt		**4,736**	5,759	**2,687**	2,987
Long-term debt due within one year					
7.55% notes(1)(3)	2016	**—**	277	**—**	200
6.20% notes(1)(5)	2017	**403**	—	**300**	—
Long-term debt due within one year		**403**	277	**300**	200

(1) *All of the Company's U.S. denominated debt is designated as a hedge of the Company's net investment in its U.S. refining operations. Refer to Note 24 for foreign exchange risk management through hedge of net investment.*

(2) *Calculated using the effective interest rate method.*

(3) *The 7.55% notes represent unsecured securities under a trust indenture dated October 31, 1996.*

(4) *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*

(5) *The 6.20%, the 7.25%, the 3.95%, the 4.00% and the 6.80% notes represent unsecured securities under a trust indenture dated September 11, 2007.*

(6) *The 5.00% and the 3.55% notes represents unsecured securities under a trust indenture dated December 21, 2009.*

During the year ended December 31, 2016, the Company had net cumulative long-term debt repayments of $768 million (2015 - net cumulative long-term debt issuance of $949 million) towards the Company's syndicated credit facilities and long-term debt.

Credit Facilities

On March 9, 2016, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facilities, previously set to expire on December 14, 2016, was extended to March 9, 2020. In addition, the Company's leverage covenant under both of its revolving syndicated credit facilities was modified to a debt to capital covenant calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. This covenant is used to assess the Company's financial strength. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2016 and assesses the risk of non-compliance to be low. As at December 31, 2016, the Company had no borrowings under its $2.0 billion facility expiring March 9, 2020 and no borrowings under its $2.0 billion facility expiring June 19, 2018 (December 31, 2015 - $499 million).

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest rates vary based on Canadian prime, Bankers' Acceptance, U.S. LIBOR or U.S. base rate, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

Notes

On February 23, 2015, the Company filed a universal short form base shelf prospectus with applicable securities regulators in each of the provinces of Canada (the "Canadian Shelf Prospectus") that enables the Company to offer up to $3.0 billion of common shares, preferred shares, debt securities, subscription receipts, warrants and other units in Canada up to and including March 23, 2017. During the 25-month period that the Canadian Shelf Prospectus is effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On March 12, 2015, the Company repaid the maturing 3.75 percent notes issued under a trust indenture dated December 21, 2009. The amount paid to noteholders was $306 million, including $6 million of interest.

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the Canadian Shelf Prospectus. The notes are redeemable at the option of the Company at any time, subject to a make whole premium unless the notes are redeemed in the three month period prior to maturity. Interest is payable semi-annually on March 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness. Net proceeds from the offering was used for general corporate purposes, which included, among other things, the partial repayment of bank debt incurred by the Company to fund early payment of U.S. $1 billion of the Company's net capital contribution payable with BP-Husky Refining LLC.

On December 22, 2015, the Company filed a universal short form base shelf prospectus (the "U.S. Shelf Prospectus") with the Alberta Securities Commission and a related U.S. registration statement containing the U.S. Shelf Prospectus with the SEC that enables the Company to offer up to U.S. $3.0 billion of debt securities, common shares, preferred shares, subscription receipts, warrants and units of the Company in the United States up to and including January 22, 2018. During the 25-month period that the U.S. Shelf Prospectus and the related U.S registration statement are effective, securities may be offered in amounts, at prices and on terms set forth in a prospectus supplement.

On November 15, 2016, the Company repaid the maturing 7.55 percent notes issued under a trust indenture dated October 31, 1996. The amount paid to noteholders was $280 million, including $10 million of interest.

At December 31, 2016, the Company had unused capacity of $1.9 billion under its Canadian Shelf Prospectus and U.S. $3.0 billion under its U.S. Shelf Prospectus and related U.S. registration statement.

The Company's notes, credit facilities and short-term lines of credit rank equally in right of payment.

Note 16 Asset Retirement Obligations

At December 31, 2016, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $11.4 billion (December 31, 2015 – $13.9 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 41 years into the future. This amount has been discounted using credit-adjusted risk-free rates of 2.8 percent to 5.3 percent (December 31, 2015 – 2.7 percent to 5.8 percent) and an inflation rate of 2 percent (December 31, 2015 – 2 percent). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO. The Company had deposited funds of $156 million (2015 – $121 million) into the restricted cash account, of which $84 million relates to the Wenchang field and have been classified as current and the remaining balance of $72 million have been classified as non-current.

The change in the provision in 2016 is primarily due to the disposition of select legacy Western Canada crude oil and natural gas assets in 2016.

While the provision is based on management's best estimates of future costs, discount rates and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

A reconciliation of the carrying amount of asset retirement obligations at December 31, 2016 and 2015 is set out below:

Asset Retirement Obligations

($ millions)	**2016**	2015
Beginning of year	**2,984**	3,065
Additions	**16**	23
Liabilities settled	**(87)**	(98)
Liabilities disposed	**(452)**	(19)
Change in discount rate	**205**	(500)
Change in estimates	**25**	340
Exchange adjustment	**(26)**	52
Accretion *(note 21)*	**126**	121
End of year	**2,791**	2,984
Expected to be incurred within 1 year	**218**	102
Expected to be incurred beyond 1 year	**2,573**	2,882

Note 17 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2016**	December 31, 2015
Employee future benefits *(note 22)*	**208**	176
Finance lease obligations	**288**	266
Stock-based compensation	**14**	12
Deferred revenue	**321**	109
Leasehold incentives	**104**	104
Other	**85**	76
End of year	**1,020**	743

Finance lease obligations

The Company, on behalf of the Sunrise Oil Sands Partnership, entered into an arrangement for the construction and use of pipeline and storage facilities in its oil sands operations. The substance of the arrangement has been determined to be a lease and has been classified as a finance lease. The assets are to be used for a minimum period of 20 years with options to renew.

The future minimum lease payments under existing finance leases are payable as follows:

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Future minimum lease payments	**35**	35	**140**	139	**764**	800	**939**	974
Interest	**30**	30	**112**	115	**505**	532	**647**	677
Present value of minimum lease payments	**33**	31	**102**	104	**153**	162	**288**	297

Deferred revenue

The deferred revenue relates to the take or pay commitment with respect to natural gas production volumes from the Liwan 3-1 field in the Asia Pacific Region not taken by the purchaser, as per the terms of the agreement. The purchaser has until the end of the agreement to take these volumes.

Note 18 Income Taxes

The major components of income tax expense for the years ended December 31, 2016 and 2015 were as follows:

Income Tax Expense (Recovery)

($ millions)	**2016**	2015
Current income tax		
Current income tax charge	**90**	308
Adjustments to current income tax estimates	**(91)**	(2)
	(1)	306
Deferred income tax		
Relating to origination and reversal of temporary differences	**(121)**	(1,760)
Adjustments to deferred income tax estimates	**150**	(67)
	29	(1,827)

Deferred Tax Items in OCI

($ millions)	**2016**	2015
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**(1)**	(1)
Remeasurement of pension plans	**(6)**	(3)
Exchange differences on translation of foreign operations	**(40)**	215
Hedge of net investment	**17**	(92)
	(30)	119

The provision for income taxes in the consolidated statements of income (loss) reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2016 and 2015 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2016**	2015
Earnings (loss) before income taxes		
Canada	**615**	(6,245)
United States	**5**	241
Other foreign jurisdictions	**330**	633
	950	(5,371)
Statutory Canadian income tax rate (percent)	**27.2%**	27.0%
Expected income tax	**258**	(1,450)
Effect on income tax resulting from:		
Capital gains and losses	**—**	2
Foreign jurisdictions	**(3)**	23
Non-taxable items	**(272)**	(31)
Revaluation of foreign tax pools	**(11)**	(14)
Other – net	**56**	(51)
Income tax expense (recovery)	**28**	(1,521)

The statutory tax rate is 27.2 percent in 2016 (2015 – 27.0 percent). The 2015 to 2016 tax rates were similar due to no significant changes to applicable tax rates.

The following reconciles the movements in the deferred income tax liabilities and assets:

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2016	Recognized in Earnings	Recognized in OCI	Other	December 31, 2016
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(4,233)	**187**	**48**	**—**	**(3,998)**
Foreign exchange gains taxable on realization	(42)	**(166)**	**(16)**	**—**	**(224)**
Debt issue costs	(1)	**(1)**	**—**	**—**	**(2)**
Other temporary differences	141	**(162)**	**—**	**—**	**(21)**
Deferred tax assets					
Pension plans	43	**(17)**	**6**	**—**	**32**
Asset retirement obligations	892	**(196)**	**(3)**	**—**	**693**
Loss carry-forwards	75	**319**	**(5)**	**—**	**389**
Financial assets at fair value	13	**7**	**—**	**—**	**20**
	(3,112)	**(29)**	**30**	**—**	**(3,111)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2015	Recognized in Earnings	Recognized in OCI	Other	December 31, 2015
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(5,840)	1,853	(240)	(6)	(4,233)
Foreign exchange gains taxable on realization	(35)	(100)	93	—	(42)
Debt issue costs	(1)	—	—	—	(1)
Deferred tax assets					
Pension plans	39	1	3	—	43
Asset retirement obligations	870	6	16	—	892
Loss carry-forwards	87	(21)	9	—	75
Financial assets at fair value	12	1	—	—	13
Other temporary differences	54	87	—	—	141
	(4,814)	1,827	(119)	(6)	(3,112)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2016, the Company has no deferred tax liabilities in respect to these investments (December 31, 2015 - nil).

At December 31, 2016, the Company had $1,257 million (December 31, 2015 – $174 million) of U.S. tax losses that will expire between 2030 and 2036. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the U.S. jurisdiction to utilize these losses.

Note 19 Share Capital

Common Shares

The Company is authorized to issue an unlimited number of no par value common shares.

Common Shares	Number of Shares	Amount *($ millions)*
December 31, 2014	983,738,062	6,986
Stock dividends	590,853	14
December 31, 2015	984,328,915	7,000
Stock dividends	**21,122,939**	**296**
December 31, 2016	**1,005,451,854**	**7,296**

Quarterly dividends may be declared in an amount expressed in dollars per common share or could be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume-weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume-weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

The Company issued stock dividends of $296 million on January 11, 2016, on account of common share dividends declared for the third quarter of 2015 (2015 – $1,167 million in cash and $14 million in common shares). The common share and cash dividend was suspended by the Board of Directors in the fourth quarter of 2015 (2015 – declared $1.20 per common share). At December 31, 2016, the Company had no common share dividends payable (December 31, 2015 – $296 million in common shares).

Preferred Shares

The Company is authorized to issue an unlimited number of no par value preferred shares.

Cumulative Redeemable Preferred Shares	Number of Shares	Amount *($ millions)*
December 31, 2014	22,000,000	534
Series 5 issued, net of share issue costs	8,000,000	195
Series 7 issued, net of share issue costs	6,000,000	145
December 31, 2015	36,000,000	874
Series 1 shares converted to Series 2 shares	**(1,564,068)**	**(38)**
Series 2 shares converted from Series 1 shares	**1,564,068**	**38**
December 31, 2016	**36,000,000**	**874**

On February 16, 2016, Husky announced that it did not intend to exercise its right to redeem its Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") on March 31, 2016. As a result, subject to certain conditions, the holders of Series 1 Preferred Shares were notified of their right to choose one of the following options with regard to their shares: retain any or all of their Series 1 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly; or convert, on a one-for-one basis, any or all of their Series 1 Preferred Shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares") of Husky Energy and receive a floating rate quarterly dividend. On March 31, 2016, holders of 1,564,068 Series 1 Preferred Shares exercised their option to convert their shares, on a one-for-one basis, to Series 2 Preferred Shares.

Cumulative Redeemable Preferred Shares Dividends

($ millions)	2016 Declared	2016 Paid	2015 Declared	2015 Paid
Series 1 Preferred Shares	**9**	**7**	13	13
Series 2 Preferred Shares[(1)]	**—**	**—**	—	—
Series 3 Preferred Shares	**11**	**8**	12	12
Series 5 Preferred Shares	**9**	**7**	7	7
Series 7 Preferred Shares	**7**	**5**	4	4
	36	**27**	36	36

(1) Series 2 Preferred shares dividends declared and paid were less than $1 million.

At December 31, 2016 there were $9 million of Preferred Share dividends payable (2015 - $nil).

Holders of the Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 2.40 percent annually for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the 5-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"), subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend that is reset every quarter for a five year period ending March 31, 2021, as and when declared by the Company's Board of Directors. The dividend rate applicable to the Series 2 Preferred Shares, for the three month period commencing September 30, 2016 but excluding December 31, 2016, was 2.242 percent based on the sum of the Government of Canada 90 day Treasury bill rate on August 31, 2016 plus 1.73 percent. Holders of Series 2 Preferred Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending December 31, 2019 as and when declared by the Company's Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

On March 12, 2015, the Company issued eight million Cumulative Redeemable Preferred Shares, Series 5 (the "Series 5 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $200 million, by way of a prospectus supplement dated March 5, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $195 million. Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

On June 17, 2015, the Company issued six million Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") at a price of $25.00 per share for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015, to the Canadian Shelf Prospectus. Net proceeds after share issue costs were $145 million. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

Stock Option Plan

Pursuant to the Incentive Stock Option Plan (the "Option Plan"), the Company may grant from time to time to officers and employees of the Company options to purchase common shares of the Company. The term of each option is five years, and vests one-third on each of the first three anniversary dates from the grant date. The Option Plan provides the option holder with the right to exercise the option to acquire one common share at the exercise price or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the grant date. When the stock option is surrendered to the Company, the cash payment is equal to the excess of the aggregate fair market value of the common shares able to be purchased pursuant to the vested and exercisable portion of such stock options on the date of surrender over the aggregate exercise price for those common shares pursuant to those stock options. The fair market value of common shares is calculated as the closing price of the common shares on the date on which board lots of common shares have traded immediately preceding the date a holder of the stock options provides notice to the Company that he or she wishes to surrender his or her stock options to the Company in lieu of exercise.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2016 was $8 million (December 31, 2015 – $1 million) representing the estimated fair value of options outstanding. The total expense recognized in selling, general and administrative expenses in the consolidated statements of income (loss) for the Option Plan for the year ended December 31, 2016 was $7 million (2015 – $39 million recovery). At December 31, 2016, stock options exercisable for cash had an intrinsic value of $1 million (December 31, 2015 – nil).

The following options to purchase common shares have been awarded to officers and certain other employees:

Outstanding and Exercisable Options	**2016**		2015	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**27,621**	**28.79**	26,742	29.47
Granted[(1)]	**5,381**	**15.67**	5,681	25.35
Surrendered for cash	**—**	**—**	(632)	26.65
Expired or forfeited	**(7,543)**	**27.94**	(4,170)	28.76
Outstanding, end of year	**25,459**	**26.26**	27,621	28.79
Exercisable, end of year	**15,662**	**29.03**	16,635	28.59

[(1)] *Options granted during the year ended December 31, 2016 were attributed a fair value of $2.26 per option (2015 – $2.56) at grant date.*

Outstanding and Exercisable Options	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$14.20 – $29.99	15,889	22.44	2.46	7,752	25.60
$30.00 – $36.20	9,570	32.59	1.71	7,910	32.39
December 31, 2016	**25,459**	**26.26**	**2.18**	**15,662**	**29.03**

The fair value of the share options is estimated at each reporting date using the Black-Scholes option pricing model, taking into account the terms and conditions upon which the share options are granted and for the performance options, the current likelihood of achieving the specified target. The following table lists the assumptions used in the Black-Scholes option pricing model for the share options and performance options:

Black-Scholes Assumptions	December 31, 2016	December 31, 2015
	Tandem Options	Tandem Options
Dividend per option	**0.96**	1.20
Range of expected volatilities used *(percent)*	**24.9 - 39.6**	24.6 - 54.8
Range of risk-free interest rates used *(percent)*	**0.4 - 1.1**	0.4 - 0.7
Expected life of share options from vesting date *(years)*	**1.91**	1.86
Expected forfeiture rate *(percent)*	**9.3**	9.4
Weighted average exercise price	**27.72**	29.03
Weighted average fair value	**0.37**	0.03

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur. The expected volatility reflects the assumption that the historical volatility over a period similar to the expected life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company's total shareholder return relative to a peer group of companies and achieving a ROCIU target set by the Company. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. Upon vesting, PSU holders receive a cash payment equal to the number of vested PSUs multiplied by the weighted average trading price of the Company's common shares for the five preceding trading days. As at December 31, 2016, the carrying amount of the liability relating to PSUs was $24 million (December 31, 2015 – $17 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income (loss) for the PSUs for the year ended December 31, 2016 was $26 million (2015 – nil). The Company paid out $18 million (2015 – $21 million paid) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2016 was one and a half years (December 31, 2015 – one and a half years).

The number of PSUs outstanding was as follows:

Performance Share Units	2016	2015
Beginning of year	**5,122,626**	4,159,228
Granted	**2,250,110**	2,374,330
Exercised	**(1,167,256)**	(775,313)
Forfeited	**(1,341,790)**	(635,619)
Outstanding, end of year	**4,863,690**	5,122,626
Vested, end of year	**1,490,243**	1,176,980

Earnings per Share

Earnings per Share

($ millions)	2016	2015
Net earnings (loss)	**922**	(3,850)
Effect of dividends declared on preferred shares in the year	**(36)**	(36)
Net earnings (loss) – basic	**886**	(3,886)
Dilutive effect of accounting for share options as equity-settled[1]	**(3)**	(57)
Net earnings (loss) – diluted	**883**	(3,943)

(millions)		
Weighted average common shares outstanding – basic and diluted	**1,004.9**	984.1

Earnings (loss) per share – basic ($/share)	**0.88**	(3.95)
Earnings (loss) per share – diluted ($/share)	**0.88**	(4.01)

(1) *Stock-based compensation expense was $7 million based on cash-settlement for the year ended December 31, 2016 (2015 – $39 million recovery). Stock-based compensation expense was $10 million based on equity-settlement for the year ended December 31, 2016 (2015 – $18 million expense). For the year ended December 31, 2016, equity-settlement of share options was considered more dilutive than the cash-settlement of share options and as such, was used to calculate earnings per share - diluted.*

For the year ended December 31, 2016, all 25 million tandem options (2015 – 28 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 20 Production, Operating and Transportation and Selling, General and Administrative Expenses

The following tables summarizes production, operating and transportation expenses in the consolidated statements of income (loss) for the years ended December 31, 2016 and 2015:

($ millions)	2016	2015
Services and support costs	**983**	1,144
Salaries and benefits	**631**	626
Materials, equipment rentals and leases	**259**	298
Energy and utility	**413**	450
Licensing fees	**246**	251
Transportation	**30**	62
Other	**162**	163
Total production, operating and transportation expenses	**2,724**	2,994

The following table summarizes selling, general and administrative expenses in the consolidated statements of income (loss) for the years ended December 31, 2016 and 2015:

($ millions)	**2016**	2015
Employee costs[1]	**319**	251
Stock based compensation[2]	**33**	(39)
Contract services	**85**	77
Equipment rentals and leases	**36**	31
Maintenance and other	**71**	22
Total selling, general and administrative expenses	**544**	342

(1) Employee costs are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.
(2) Stock-based compensation expense (recovery) represents the cost to the Company for participation in share-based payment plans.

Note 21 Financial Items

Financial Items

($ millions)	**2016**	2015
Foreign exchange		
Gains (losses) on translation of U.S. dollar denominated long-term debt	**—**	(34)
Gains on non-cash working capital	**4**	35
Other foreign exchange gains	**9**	42
Net foreign exchange gains	**13**	43
Finance income	**17**	35
Finance expenses		
Long-term debt	**(330)**	(300)
Contribution payable *(note 11)*	**(6)**	(16)
Other	**(17)**	(18)
	(353)	(334)
Interest capitalized[1]	**78**	157
	(275)	(177)
Accretion of asset retirement obligations *(note 16)*	**(126)**	(121)
Finance expenses	**(401)**	(298)
Total Financial Items	**(371)**	(220)

(1) Interest capitalized on project costs in 2016 is calculated using the Company's annualized effective interest rate of 5 percent (2015 – 5 percent).

Note 22 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The other post-employment benefit plan provides certain retired employees with health care and dental benefits. The Company also maintains a defined benefit pension plan, which is closed to new entrants. The defined benefit pension plan provides pension benefits to certain employees based on years of service and final average earnings. The amount and timing of funding of these plans is subject to the funding policy as approved by the Board of Directors.

The measurement date of all plan assets and the accrued benefit obligations was December 31, 2016. The Company is required to file an actuarial valuation of its defined benefit pension with the provincial or state regulator at least every three years. The most recent actuarial valuation was December 31, 2015 for the Canadian defined benefit plan. The most recent actuarial valuation was December 31, 2014 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was December 31, 2015.

Defined Contribution Pension Plan

During the year ended December 31, 2016, the Company recognized a $46 million expense (2015 – $44 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

Defined Benefit Pension Plan ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

Defined Benefit Obligation	DB Pension Plan		OPEB Plans	
($ millions)	**2016**	2015	**2016**	2015
Beginning of year	**177**	179	**180**	143
Current service cost	**1**	4	**13**	10
Interest cost	**6**	7	**7**	6
Benefits paid	**(11)**	(11)	**(3)**	(3)
Remeasurements				
Actuarial (gain) loss – experience	**(1)**	—	**(1)**	17
Actuarial (gain) loss – financial assumptions	**6**	(2)	**17**	7
End of year	**178**	177	**213**	180

Fair Value of Plan Assets	DB Pension Plan		OPEB Plans	
($ millions)	**2016**	2015	**2016**	2015
Beginning of year	**181**	180	**—**	—
Contributions by employer	**2**	2	**—**	—
Benefits paid	**(11)**	(11)	**—**	—
Interest income	**6**	7	**—**	—
Return on plan assets greater (less) than discount rate	**5**	3	**—**	—
Settlements	**—**	—	**—**	—
End of year	**183**	181	**—**	—

Funded status	DB Pension Plan		OPEB Plans	
($ millions)	**2016**	2015	**2016**	2015
Net asset (liability)	**5**	4	**(213)**	(180)

The Company has accrued the total net liability for the DB Pension Plan and the OPEB Plans in the consolidated balance sheets in other long-term liabilities.

The composition of the DB Pension Plan assets at December 31, 2016 and 2015 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	2016	2015
Money market type funds	0 - 5	**0.6**	0.5
Equity securities	30 - 50	**43.8**	41.5
Debt securities	50 - 65	**55.6**	58.0

The following tables summarize amounts recognized in net earnings and OCI for the DB Pension Plan and the OPEB Plans for the years ended December 31, 2016 and 2015:

	DB Pension Plan		OPEB Plans	
($ millions)	**2016**	2015	**2016**	2015
Amounts recognized in net earnings				
Current service cost	**1**	4	**13**	10
Net Interest cost	**—**	—	**7**	6
Gain on settlement	**—**	—	**—**	—
Benefit cost (gain)	**1**	4	**20**	16
Remeasurements				
Actuarial (gain) loss due to liability experience	**(1)**	—	**(1)**	17
Actuarial (gain) loss due to liability assumption changes	**6**	(2)	**17**	7
Loss (gain) on plan assets	**(5)**	(3)	**—**	—
Remeasurement effects recognized in OCI	**—**	(5)	**16**	24

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

Assumptions

	DB Pension Plan		OPEB Plans	
(percent)	**2016**	2015	**2016**	2015
Discount rate for benefit expense and obligation	**3.5 - 3.8**	3.7 - 3.8	**3.7 - 4.1**	3.7 - 4.1
Rate of compensation expense	**3.5**	3.5	**N/A**	N/A

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 7.0 percent for 2016, grading 0.4 percent per year for 5 years to 5.0 percent in 2021 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 7.0 percent for 2016, grading 0.4 percent per year for 5 years to 5.0 percent in 2021 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 6.5 percent for 2016, grading 0.25 percent per year for 6 years to 5.0 percent per year in 2022 and thereafter. The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.3 percent for 2016, grading 0.21 percent per year for 6 years to 5.0 percent in 2022 and thereafter.

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

Sensitivity Analysis

	DB Pension Plan		OPEB Plans	
($ millions)	1% increase	1% decrease	1% increase	1% decrease
Discount rate	(18)	20	(36)	41
Health Care Cost Trend Rate	N/A	N/A	40	(32)

Note 23 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2016	2015
Decrease (increase) in non-cash working capital		
Accounts receivable	**(340)**	844
Inventories	**(334)**	570
Prepaid expenses	**131**	10
Accounts payable and accrued liabilities	**316**	(926)
Change in non-cash working capital	**(227)**	498
Relating to:		
Operating activities	**(235)**	651
Financing activities	**281**	179
Investing activities	**(273)**	(332)

Note 24 Financial Instruments and Risk Management

Financial Instruments

The Company's financial instruments include cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, derivatives, portions of other assets and other long-term liabilities.

The following table summarizes the Company's financial instruments that are carried at fair value in the Consolidated Balance Sheets:

Financial Instruments at Fair Value

($ millions)	December 31, 2016	December 31, 2015
Commodity contracts - fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**5**	6
Crude oil[(2)]	**(30)**	8
Other assets - FVTPL	**1**	2
Hedge of net investment[(3)(4)]	**(827)**	(940)
End of year	**(851)**	(924)

(1) *Natural gas contracts includes an $11 million increase at December 31, 2016 (December 31, 2015 – $14 million decrease) to the fair value of held-for-trading inventory, recognized in the Consolidated Balance Sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $45 million at December 31, 2016 (December 31, 2015 – $67 million).*
(2) *Crude oil contracts includes an $17 million increase at December 31, 2016 (December 31, 2015 – $6 million decrease) to the fair value of held-for-trading inventory, recognized in the Consolidated Balance Sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $354 million at December 31, 2016 (December 31, 2015 – $190 million).*
(3) *Hedging instruments are presented net of tax.*
(4) *Represents the translation of the Company's U. S. denominated long-term debt designated as a hedge of the Company's net investment in its U.S. refining operations.*

The Company's other financial instruments that are not related to derivatives, contingent consideration or hedging activities are included in cash and cash equivalents, accounts receivable, restricted cash, income tax receivable, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, and portions of other assets and other long-term liabilities. These financial instruments are classified as loans and receivables or other financial liabilities and are carried at amortized cost. Excluding long-term debt, the carrying values of these financial instruments and cash and cash equivalents approximate their fair values.

The fair value of long-term debt represents the present value of future cash flows associated with the debt. Market information, such as treasury rates and credit spreads, are used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. The estimated fair value of long-term debt at December 31, 2016 was $5.5 billion (December 31, 2015 – $5.6 billion).

The estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates exit prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability. The estimation of the fair value of the net investment hedge incorporates foreign exchange rates and market interest rates from financial institutions. All financial assets and liabilities are classified as Level 2 measurements.

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. It is also exposed to financial risks related to liquidity and credit and contract risks. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. Derivative instruments are recorded at fair value in accounts receivable, inventory, other assets and accounts payable and accrued liabilities in the Consolidated Balance Sheets. The Company has crude oil and natural gas inventory held in storage related to commodity price risk management contracts that is recognized at fair value. The Company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and inventory or volumes in long distance transit. The Company may also use firm commitments for the purchase or sale of crude oil and natural gas. For the year ended December 31, 2016, the Company incurred a realized loss of $121 million on a short-term corporate hedging program, which is recorded in other-net in the Consolidated Statements of Income (Loss). The hedging program concluded in June 2016.

The Company's results will be impacted by a decrease in the price of crude oil and natural gas inventory. The Company has crude oil inventories that are feedstock, held at terminals or part of the in-process inventories at its refineries and at offshore sites. The Company also has natural gas inventory that could have an impact on earnings based on changes in natural gas prices. All these inventories are subject to a lower of cost or net realizable value test on a monthly basis.

Foreign Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies, including the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or from the sale of oil and gas commodities that receive prices determined by reference to U.S. benchmark prices. An increase in the value of the Canadian dollar relative to the U.S. dollar will decrease the revenues received from the sale of oil and gas commodities. Correspondingly, a decrease in the value of the Canadian dollar relative to the U.S. dollar will increase the revenues received from the sale of oil and gas commodities. The majority of the Company's expenditures are in Canadian dollars. The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these fluctuations and to mitigate its exposure to foreign exchange risk.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company may enter into cash flow hedges using cross currency debt swap arrangements. In addition, the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation that has a U.S. dollar functional currency. The unrealized foreign exchange gain or loss related to this hedge is recorded in OCI.

At December 31, 2016, the Company had designated U.S. $3.0 billion denominated debt as a hedge of the Company's selected net investments in its foreign operations with a U.S. dollar functional currency (December 31, 2015 – U.S. $3.2 billion). For the year ended December 31, 2016, the unrealized gain arising from the translation of the debt was $113 million (December 31, 2015 – unrealized loss of $587 million), net of tax loss of $17 million (December 31, 2015 – recovery of $92 million), which was recorded in hedge of net investment within OCI.

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. To mitigate risk related to interest rates, the Company may enter into fair value or cash flow hedges using interest rate swaps.

At December 31, 2016, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that had previously been designated as a fair value hedge was $2 million (December 31, 2015 – $4 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $2 million for the year ended December 31, 2016 (December 31, 2015 – $22 million).

At December 31, 2016, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $18 million (December 31, 2015 – $20 million), net of tax of $6 million (December 31, 2015 – net of tax of $7 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an offset to finance expense of $2 million for the year ended December 31, 2016 (December 31, 2015 – $3 million).

ii) Earnings Impact of Market Risk Management Contracts

The gains (losses) recognized on other risk management positions for the years ended December 31, 2016 and 2015 are set out below:

Earnings Impact	**2016**		
($ millions)	Marketing and Other	Other – Net	Net Foreign Exchange
Commodity Price			
Natural gas	**(1)**	**—**	**—**
Crude oil	**(38)**	**—**	**—**
Crude oil call options	**—**	**(67)**	**—**
Crude oil put options	**—**	**(54)**	**—**
	(39)	**(121)**	**—**
Foreign Currency			
Foreign currency forwards[1]	**—**	**—**	**10**
	(39)	**(121)**	**10**

[1] *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income (loss).*

Earnings Impact	2015		
($ millions)	Marketing and Other	Other – Net	Net Foreign Exchange
Commodity Price			
Natural gas	11	—	—
Crude oil	4	—	—
	15	—	—
Foreign Currency			
Foreign currency forwards[1]	—	1	(28)
	15	1	(28)

[1] *Unrealized gains or losses from short-dated foreign currency forwards are included in other – net, while realized gains or losses are included in net foreign exchange gains in the consolidated statements of income (loss).*

Offsetting Financial Assets and Liabilities

The tables below outline the financial assets and financial liabilities that are subject to set-off rights and related arrangements, and the effect of those rights and arrangements on the consolidated balance sheets:

Offsetting Financial Assets and Liabilities *($ millions)*	As at December 31, 2016 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	**57**	**(38)**	**19**
Normal purchase and sale agreements	**529**	**(199)**	**330**
End of year	**586**	**(237)**	**349**
Financial Liabilities			
Financial derivatives	**(161)**	**70**	**(91)**
Normal purchase and sale agreements	**(644)**	**234**	**(410)**
End of year	**(805)**	**304**	**(501)**

Offsetting Financial Assets and Liabilities *($ millions)*	As at December 31, 2015 Gross Amount	 Amount Offset	 Net Amount
Financial Assets			
Financial derivatives	87	(37)	50
Normal purchase and sale agreements	353	(122)	231
End of year	440	(159)	281
Financial Liabilities			
Financial derivatives	(108)	48	(60)
Normal purchase and sale agreements	(368)	68	(300)
End of year	(476)	116	(360)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[1] *($ millions)*	10% price increase	10% price decrease
Crude oil price	(6)	6
Natural gas price	(7)	7

Foreign Exchange Rate[2] *($ millions)*	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar[3]	—	—

(1) *Based on average crude oil and natural gas market prices as at December 31, 2016.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2016.*
(3) *Foreign Exchange sensitivity on U.S. dollar per Canadian dollar is less than $1 million.*

b) Financial Risk

i) Liquidity Risk Management

Liquidity risk is the risk that the Company will not be able to meet 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. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it has access to multiple sources of capital including cash and cash equivalents, cash from operating activities, undrawn credit facilities and capability to raise capital from various debt and equity capital markets under its shelf prospectuses. The Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

Since the Company operates in the Upstream oil and gas industry, it requires significant cash to fund capital programs necessary to maintain or increase production, develop reserves, acquire strategic oil and gas assets and repay maturing debt. The Company's upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. During times of low oil and gas prices, a portion of capital programs can generally be deferred. However, due to the long cycle times and the importance to future cash flow of maintaining the Company's production, it may be necessary to utilize alternative sources of capital to continue the Company's strategic investment plan during periods of low commodity prices. As a result, the Company frequently evaluates the options available with respect to sources of short and long-term capital resources. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2016:

Credit Facilities

($ millions)	Available	Unused
Operating facilities[(1)] *(note 13)*	**670**	**292**
Syndicated bank facilities[(2)] *(note 15)*	**4,000**	**3,800**
End of year	**4,670**	**4,092**

[(1)] *Consists of demand credit facilities and letter of credit.*
[(2)] *Commercial paper outstanding is supported by the Company's Syndicated credit facilities.*

In addition to the credit facilities listed above, the Company had unused capacity under the Canadian Shelf Prospectus of $1.9 billion and unused capacity under the U.S Shelf Prospectus and related U.S registration statement of U.S. $3.0 billion. The ability of the Company to raise additional capital utilizing these Shelf Prospectuses is dependent on market conditions.

The Company believes it has sufficient funding through the use of these facilities and access to the capital markets to meet its future capital requirements.

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company had one external customer that constituted more than 10 percent of gross revenues during the years ended December 31, 2016 and December 31, 2015. Sales to this customer were approximately $1,832 million for the year ended December 31, 2016 (December 31, 2015 – $2,868 million).

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amounts of cash and cash equivalents, accounts receivable and restricted cash represent the Company's maximum credit exposure.

The Company's accounts receivable was aged as follows at December 31, 2016:

Accounts Receivable Aging

($ millions)	December 31, 2016
Current	873
Past due (1 – 30 days)	148
Past due (31 – 60 days)	4
Past due (61 – 90 days)	3
Past due (more than 90 days)	40
Allowance for doubtful accounts	(32)
	1,036

The Company recognizes a valuation allowance when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2016, the Company wrote off $3 million (December 31, 2015 – $7 million) of uncollectible receivables.

Note 25 Related Party Transactions

Significant subsidiaries and jointly controlled entities at December 31, 2016 and the Company's percentage equity interest (to the nearest whole number) are set out below:

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Subsidiary of Husky Energy Inc.		
Husky Oil Operations Limited	100	Alberta
Subsidiaries and jointly controlled entities of Husky Oil Operations Limited		
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Husky Energy International Corporation	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm's length transactions unless otherwise noted.

On July 15, 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan for gross proceeds of $1.69 billion in cash. The assets include approximately 1,900 kilometres of pipeline in the Lloydminster region, 4.1 mmbbls of storage capacity at Hardisty and Lloydminster and other ancillary assets. The assets are held by a newly-formed limited partnership, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. This transaction is a related party transaction, as PAH and CKI are affiliates of one of the Company's principal shareholders, and has been measured at fair value. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Subsequent to the sale of its ownership interest, the Company performs management services as the operator of the pipeline for which it earns a management fee from HMLP.The Company is also the contractor for HMLP and constructs its assets on a cost recovery basis with certain restrictions. HMLP charges an access fee to the Company for the use of its pipeline systems in performing its blending business and the Company also pays for transportation and storage services. For the year ended December 31, 2016, the Company charged HMLP $133 million related to construction and management services, and the Company had purchases from HMLP of $15 million related to the use of the pipeline for the Company's blending activities and $64 million related to transportation and storage. As at December 31, 2016, the Company had $26 million due from HMLP and nil due to HMLP related to these transactions. All transactions with HMLP have been measured at fair value.

The Company sells natural gas to and purchases steam from the Meridian Limited Partnership ("Meridian"), owner of the Meridian cogeneration facility, for use at the facility, Upgrader and Lloydminster ethanol plant. In addition, the Company provides facilities services and personnel for the operations of the Meridian cogeneration facility, which are primarily measured and reimbursed at cost. These transactions are related party transactions, as Meridian is an affiliate of one of the Company's principal shareholders, and have been measured at fair value. For the year ended December 31, 2016, the amount of natural gas sales to Meridian totalled $41 million (December 31, 2015 – $50 million). For the year ended December 31, 2016, the amount of steam purchased by the Company from Meridian totalled $13 million (December 31, 2015 – $16 million). For the year ended December 31, 2016, the total cost recovery by the Company for facilities services was $12 million (December 31, 2015 – $17 million). At December 31, 2016 the Company had under $1 million due from Meridian with respect to these transactions (December 31, 2015 – $2 million).

At December 31, 2016, $34 million of the May 11, 2009 7.25 percent senior notes were held by a related party, Ace Dimension Limited, and are included in long-term debt in the Company's consolidated balance sheet. The related party transaction was measured at fair market value at the date of the transaction and has been carried out on the same terms as applied with unrelated parties.

On June 29, 2011, the Company issued 7.4 million common shares at a price of $27.05 per share for total gross proceeds of $200 million in a private placement to its then principal shareholders, L.F. Management and Investment S.à r.l (formerly L.F. Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares.

On December 7, 2010, the Company issued 28.9 million common shares at a price of $24.50 per share for total gross proceeds of $707 million in a private placement to its principal shareholders, L.F.Management and Investment S.à r.l (formerly L.F.Investments (Barbados) Limited) and Hutchison Whampoa Luxembourg Holdings S.à r.l, which was completed in conjunction with a public offering by the Company of common shares in Canada.

The Company defines its key management as the officers and executives within the executive department of the Company. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel:

Compensation of Key Management Personnel

($ millions)	**2016**	2015
Short-term employee benefits[(1)]	**9**	15
Stock-based compensation[(2)]	**4**	8
	13	23

[(1)] Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.

[(2)] Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.

Note 26 Commitments and Contingencies

At December 31, 2016, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheets:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases[(1)]	252	535	1,650	2,437
Firm transportation agreements[(1)]	458	1,851	4,822	7,131
Unconditional purchase obligations[(2)]	2,749	4,841	1,549	9,139
Lease rentals and exploration work agreements	49	244	850	1,143
Obligations to fund equity investee[(3)]	52	220	379	651
	3,560	7,691	9,250	20,501

[(1)] Included in operating leases and firm transportation agreements are blending and storage agreements and transportation commitments of $0.6 billion and $2.1 billion respectively with HMLP.

[(2)] Includes purchase of refined petroleum products, processing services, distribution services, insurance premiums, drilling services and natural gas purchases.

[(3)] Equity investee refers to the Company's investment in Husky-CNOOC Madura Limited and HMLP which is accounted for using the equity method.

The Company has income tax and royalty filings that are subject to audit and potential reassessment. The findings may impact the liabilities of the Company. The final results are not reasonably determinable at this time, and management believes that it has adequately provided for current and deferred income taxes.

The Company is involved in various claims and litigation arising in the normal course of business. While the outcome of these matters is uncertain and there can be no assurance that such matters will be resolved in the Company's favour, the Company does not currently believe that the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters would have a material adverse impact on its financial position, results of operations or liquidity.

Note 27 Capital Disclosures

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk, and to maintain investor, creditor and market confidence to sustain the future development of the business. The Company manages its capital structure and makes adjustments as economic conditions and the risk characteristics of its underlying assets change. The Company considers its capital structure to include shareholders' equity and debt which was $23.0 billion as at December 31, 2016 (December 31, 2015 – $23.3 billion). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt and/or adjust its capital spending to manage its current and projected debt levels.

The Company monitors its capital structure and financing requirements using, among other things, non-GAAP financial metrics consisting of debt to capital employed and debt to funds from operations. Debt to capital employed is defined as long-term debt, long-term debt due within one year, and short-term debt divided by capital employed which is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Debt to funds from operations is defined as long-term debt, long-term debt due within one year and short-term debt divided by funds from operations which is equal to cash flow - operating activities less the settlement of asset retirement obligations, deferred revenue, income taxes received (paid) and change in non-cash working capital.

The Company's objective is to maintain a debt to capital employed target of less than 25 percent and a debt to funds from operations ratio of less than 2.0 times. At December 31, 2016, debt to capital employed was 23.2 percent (December 31, 2015 – 28.9 percent) which was within the Company's target and debt to funds from operations was 2.6 times (December 31, 2015 – 2.0 times). The increase in the Company's debt to funds from operations ratio as at December 31, 2016 reflects the impact of continued operations in the low commodity price environment which resulted in significantly lower funds from operations compared to 2015. The Company has taken measures to strengthen its financial position and navigate through this commodity down cycle which include, but are not limited to, a reduction of budgeted capital spending, the suspension of the quarterly common share dividend, the sale of royalty interests in Western Canada production, the sale of non-core assets in Western Canada, a strategic disposition of select midstream assets and the continued transition to lower sustaining and higher return Lloyd thermal projects. To facilitate the management of these ratios, the Company prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The annual budget is approved by the Board of Directors.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a debt to capital covenant used to assess the Company's financial strength. The Company's leverage covenant under both of its revolving syndicated credit facilities was modified to a debt to capital covenant calculated as total debt (long-term debt including long-term debt due within one year and short-term debt) and certain adjusting items specified in the agreement divided by total debt, shareholders' equity and certain adjusting items specified in the agreement. If the Company does not comply with the covenants under the syndicated credit facilities, there is the risk that repayment could be accelerated. The Company was in compliance with the syndicated credit facility covenants at December 31, 2016 and assesses the risk of non-compliance to be low.

There were no changes in the Company's approach to capital management from the previous year.

Note 28 Government Grants

The Company has government assistance programs in place where it receives funding based on ethanol production and sales from the Lloydminster and Minnedosa ethanol plants from the Department of Natural Resources and the Government of Manitoba. Applications for funding are submitted quarterly. During 2015, the Company received $21 million under these programs. The programs expired in 2015.