



FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2016

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2016 FOURTH QUARTER AND YEAR END RESULTS

Commenting on 2016 results, Steve Laut, President of Canadian Natural stated, "Throughout 2016 Canadian Natural continued to execute on our defined strategy with another strong operational year. In 2016 we were able to keep our capital program intact, complete the Phase 2B expansion at Horizon, continue to lower our cost structures, operate our properties in a safe and effective manner and increase returns to shareholders.

2016 was a milestone year for Canadian Natural with the continued transition to a long life low-decline asset base with the strong execution and operational results of Horizon Phase 2B. In the fourth quarter of 2016 the Company achieved record SCO production of 178,000 bbl/d and record low operating costs of \$22.53 were realized as cost efficiencies continue to be a focus. Production levels at Horizon continue to be in excess of our 182,000 bbl/d nameplate capacity with December, January and February production averaging approximately 184,000 bbl/d, 195,000 bbl/d and 202,600 bbl/d respectively. Strong production combined with record low operating costs is delivering substantial cash flow generation and as a result our balance sheet is strengthening quickly. This will allow for greater returns to shareholders, as demonstrated by today's 10% dividend increase, economic development of our asset base and potential for opportunistic acquisitions.

2017 will be equally as transformational as Canadian Natural targets to deliver 6% production growth with a \$3.9 billion capital program. With approximately \$1.05 billion of Horizon Phase 3 expansion capital remaining to be spent in 2017 as a part of this capital program, an additional 80,000 bbl/d of SCO will be added at Horizon. Phase 3 is targeted to start-up in the fourth quarter of 2017 and will further strengthen the Company's long term sustainability in any commodity price cycle."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "In 2016 Canadian Natural demonstrated the strength and resilience of the Company's operations and assets. While navigating a US\$43/bbl average WTI price in 2016, the Company's net ending debt was largely unchanged compared with 2015 levels, all the while growing proved reserves 4%, increasing dividends, maintaining entry to exit production levels and investing approximately \$1.9 billion in the Horizon expansion. A significant achievement in a low commodity price environment. In the fourth quarter of 2016, the Company generated approximately \$1.0 billion in free cash flow after capital and dividend requirements. As a result, liquidity and key balance sheet metrics of the corporation strengthened in 2016.

In the first quarter of 2017 the balance sheet will continue to strengthen as cash flow is targeted to exceed capital expenditures by approximately \$230 million per month. In recognition of this financial strength and the strong operational performance at Horizon, our Board of Directors today approved a 10% increase to our quarterly dividend from \$0.25 per share to \$0.275 per share, for the seventeenth consecutive year. Also, as a result of this financial strength and operational performance, the Board of Directors, subject to regulatory approval, authorized the Company to apply for a normal course issuer bid to purchase up to 2.5% of the Company's common shares.

With increased long life low-decline, high value SCO production from Horizon Phase 2B in 2016 and Phase 3 targeted for a fourth quarter start-up, Canadian Natural's business becomes even more robust and sustainable, allowing for increased capital flexibility going forward."

QUARTERLY HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net earnings (loss)	\$ 566	\$ (326)	\$ 131	\$ (204)	\$ (637)
Per common share – basic	\$ 0.51	\$ (0.29)	\$ 0.12	\$ (0.19)	\$ (0.58)
– diluted	\$ 0.51	\$ (0.29)	\$ 0.12	\$ (0.19)	\$ (0.58)
Adjusted net earnings (loss) from operations ⁽¹⁾	\$ 439	\$ (355)	\$ (49)	\$ (669)	\$ 263
Per common share – basic	\$ 0.40	\$ (0.32)	\$ (0.04)	\$ (0.61)	\$ 0.24
– diluted	\$ 0.40	\$ (0.32)	\$ (0.04)	\$ (0.61)	\$ 0.24
Funds flow from operations ⁽²⁾	\$ 1,677	\$ 1,021	\$ 1,379	\$ 4,293	\$ 5,785
Per common share – basic	\$ 1.52	\$ 0.93	\$ 1.26	\$ 3.90	\$ 5.29
– diluted	\$ 1.50	\$ 0.92	\$ 1.26	\$ 3.89	\$ 5.28
Net capital expenditures	\$ 411	\$ 1,185	\$ (96)	\$ 3,794	\$ 3,853
Daily production, before royalties					
Natural gas (MMcf/d)	1,646	1,645	1,703	1,691	1,726
Crude oil and NGLs (bbl/d)	585,185	460,986	572,000	523,873	564,188
Equivalent production (BOE/d) ⁽³⁾	859,577	735,212	855,800	805,782	851,901

(1) Adjusted net (loss) earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

(2) Funds flow from operations (formally cash flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to fund capital reinvestment and debt repayment. The derivation of this measure is discussed in the MD&A.

(3) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.

Annual Overview

- The Company's proven strategy which combines a diversified asset base, long-life low decline assets and low capital exposure assets continues to deliver strong sustainable cash flow, allowing Canadian Natural to balance cash flow allocation between balance sheet strength, returns to shareholders, economic resource development and opportunistic acquisitions to maximize shareholder value. Canadian Natural's capital programs are flexible and facilitate allocating capital to those projects which generate the highest returns as well as ensuring the Company effectively balance cash flow allocation.
- Annual production volumes of 805,782 BOE/d were achieved in 2016, representing a decrease of 5% from 2015 levels, however due to the successful start up of Phase 2B at Horizon Oil Sands ("Horizon") Q4/16 production volumes have increased over Q4/15. Strong results given the decrease in drilling activity in 2015 and 2016, a 83% decrease from peak levels in 2014 as the Company proactively managed through the commodity price downturn.
 - Funds flow generation was strong in 2016 with annual funds flow from operations of \$4,293 million and an adjusted net loss of \$669 million.
 - Annual crude oil and NGL production volumes in 2016 averaged 523,873 bbl/d, a decrease of 7% from 2015 levels, and were within the Company's 2016 annual guidance range of 514,000 bbl/d to 563,000 bbl/d.
 - In 2016, the Company achieved annual natural gas production volumes of 1,691 MMcf/d, a strong result given third party facility outages and Nova transportation curtailments in the year, which negatively impacted annual production by approximately 100 MMcf/d. While production levels were essentially in-line with 2015 volumes, the Company achieved operating costs of \$1.18/Mcf, a reduction of 12% from 2015 levels.

- Horizon, Canadian Natural's world class oil sands mining and upgrading operations, achieved record annual production of 123,265 bbl/d of synthetic crude oil ("SCO") in 2016, a modest increase over 2015 levels and within annual corporate guidance. In October 2016, the Company completed the Horizon Phase 2B expansion and effectively ramped up production to design capacity.
 - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized record low annual average operating costs of \$25.20/bbl, after adjusting for planned downtime in 2016, a 12% reduction from 2015 levels.
 - Strong production has continued at Horizon with December, January and February production levels of approximately 184,000 bbl/d, 195,000 bbl/d and 202,600 bbl/d of SCO, respectively.
 - During 2016, Canadian Natural continued to advance the Horizon Phase 3 expansion. The final component of the Company's transition to a long-life, low decline asset base is progressing as planned, reaching 89% physical completion as at December 31, 2016. The start-up of Phase 3 is targeted for Q4/17 and is targeted to add incremental production capacity of 80,000 bbl/d of SCO. The Horizon Phase 3 expansion will increase targeted design capacity which will result in a dramatic step change towards lower operating costs.
 - In 2016, Horizon project capital expenditures totaled \$1.92 billion, below the Company's 2015 estimate and the 2016 capital budget, impressive results given the challenges faced in the region. Additionally, in 2017, Horizon project capital expenditures are targeted to be approximately \$1.05 billion to complete the Phase 3 expansion, which remains on budget and on schedule for Q4/17 start-up.
- Thermal in situ oil sands ("thermal in situ") annual production volumes reached 111,046 bbl/d, within corporate guidance, representing an expected 14% decrease from 2015 levels, due to reduced capital allocation and the timing of steaming cycles at the Company's Primrose operations.
 - At Primrose, strong results from the Company's low pressure steamflood continue. As a result the current production under the steamflood has increased to approximately 32,000 bbl/d, representing an increase of 154% from December 2015 volumes of 12,600 bbl/d.
 - At Kirby South the Company's Steam Assisted Gravity Drainage ("SAGD") project, the Company achieved record annual production volumes of 37,714 bbl/d, a 28% increase over 2015 production.
 - Including energy costs, Kirby South achieved record low annual operating costs of \$9.33/bbl, decreasing 26% from 2015 levels. Annual Steam to Oil Ratio ("SOR") at Kirby South continued to be strong at 2.6 in 2016.
- Pelican Lake operations remained strong with annual production of 47,636 bbl/d, with record low annual operating costs of \$6.60/bbl, a 9% reduction from 2015 levels. This long-life, low decline, leading edge polymer flood continues to perform well despite no drilling activity in the past two years prior to Q4/16 due to capital allocation choices.
- North American light crude oil and NGL production was 87,983 bbl/d in 2016, essentially flat since 2014, strong results given minimal drilling due to capital allocation decisions. 2016 operating costs have been reduced year over year by 9% to \$13.48/bbl from 2015 levels.
- Primary heavy crude oil production decreased, as expected, year over year to 104,292 bbl/d in 2016, following the Company's proactive decision to reduce its primary heavy crude oil drilling program. Canadian Natural is the industry leading primary heavy crude oil producer and continue to focus on operations optimization, annual operating costs of \$13.55/bbl were realized, representing a decrease of 10% from 2015 levels.
- North American natural gas production was 1,622 MMcf/d in 2016, in-line with 2015 levels, despite the negative impact of approximately 100 MMcf/d being shut-in as a result of third party facility outages and Nova transportation curtailments in the year. Effective and efficient operations continue to deliver significant cost reductions. Operating costs in North America natural gas decreased to \$1.12/Mcf in 2016, a 12% reduction from 2015 levels.

- International Exploration & Production (“E&P”) annual production volumes were within annual production guidance and reaching 49,650 bbl/d, representing a 20% increase from 2015 levels.
 - North Sea volumes improved by 6% to 23,554 bbl/d, due to the Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea. As a result, North Sea 2016 operating costs decreased by 33% to \$42.47/bbl from 2015 levels.
 - The completion of Offshore Africa's infill drilling programs in early 2016 at Espoir and Baobab increased production by 37% to 26,096 bbl/d. Offshore Africa's operating costs were also strong in 2016 at \$18.48/bbl representing a 45% decrease from 2015 levels.
- The Company's 2016 drilling program consisted of 190 net wells, excluding strat/service wells, a 50 net well increase from its 2015 drilling program. The Company continues to be prudent with its capital allocation in a volatile commodity price environment.
- In 2016, Canadian Natural continued its focus on effective and efficient operations reducing operating costs throughout its business. As a result, the Company achieved over \$560 million in operating cost savings year-over-year based on 2015 unit rates versus 2016 unit rates.
- Results from the Company's continued cost focused strategy in 2016 are demonstrated in the table below.

Annual Operating Costs (Canadian \$)	2016	2015	Year-over-Year Percent Change
North America Light Crude Oil and NGLs (\$/bbl)	\$ 13.48	\$ 14.88	(9)%
Pelican Lake Heavy Crude Oil (\$/bbl)	\$ 6.60	\$ 7.24	(9)%
Primary Heavy Crude Oil (\$/bbl)	\$ 13.55	\$ 15.01	(10)%
Horizon Oil Sands Mining and Upgrading (\$/bbl) ⁽¹⁾	\$ 25.20	\$ 28.61	(12)%
North Sea Light Crude Oil (\$/bbl)	\$ 42.47	\$ 63.67	(33)%
Offshore Africa Light Crude Oil (\$/bbl)	\$ 18.48	\$ 33.32	(45)%
North America Natural Gas (\$/Mcf)	\$ 1.12	\$ 1.27	(12)%
Total Overall (\$/BOE)⁽²⁾⁽³⁾	\$ 13.37	\$ 15.02	(11)%

(1) Horizon annual average operating costs adjusted to reflect the impacts of turnarounds.

(2) Total overall annual operating costs per BOE reflects Horizon adjusted operating costs.

(3) Given the cyclical nature of Primrose operations, cost comparison year over year is not indicative of performance.

- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2016, the Company had in place bank credit facilities of \$7.4 billion, of which \$3.0 billion was available, an increase from \$2.35 billion at September 30, 2016. Balance sheet strength continues to be a focus of the Company, with debt to book capitalization of 39% at December 31, 2016, within the Company's targeted operating range.
- The Company remained focused on returns to shareholders in 2016 increasing dividends by approximately 9% to \$0.25/share in Q4/16, reflecting the Board of Director's confidence in the Company's cash flow. In addition, the Company distributed 21.8 million PrairieSky common shares to shareholders as a return of capital in Q2/16, valued at approximately \$546 million.
- Subsequent to December 31, 2016, Moody's Investors Service, Inc. adjusted the Company's credit rating outlook from negative to stable on the Company's investment grade credit rating.

Fourth Quarter Overview

- Canadian Natural realized funds flow from operations of \$1,677 million in Q4/16, an increase from \$1,021 million in Q3/16 and \$1,379 million in Q4/15. The increases primarily reflect higher SCO sales volumes and realized prices from Horizon, higher natural gas netbacks and higher North America E&P crude oil and NGL netbacks and the impact of reduced cash taxes in the quarter.
 - Significant free cash flow of approximately \$1,270 million was generated in Q4/16 after net dispositions and capital expenditures. After quarterly dividend requirements, approximately \$990 million of free cash flow was realized in the quarter, which was largely used to reduce the Company's debt levels.
- For Q4/16, the Company had net earnings of \$566 million compared to net earnings of \$131 million in Q4/15 and a net loss of \$326 million in Q3/16. The adjusted net earnings from operations was \$439 million in Q4/16 compared to an adjusted net loss of \$49 million in Q4/15 and an adjusted net loss of \$355 million in Q3/16. Changes in adjusted net earnings primarily reflect the changes in funds flow from operations.
- Canadian Natural's corporate production volumes averaged 859,577 BOE/d in Q4/16, slightly above Q4/15 and a 17% increase from Q3/16 volumes, primarily due to the successful ramp up of the Horizon Phase 2B expansion and strong performance from thermal in-situ.
 - As previously announced, after the completion of Phase 2B, Horizon set a new quarterly production record in Q4/16 with SCO volumes averaging 178,063 bbl/d, at the high end of previously issued Q4/16 Horizon production guidance.
 - As a result of cost efficiencies achieved at Horizon combined with strong operational results, the Company realized record low operating costs of \$22.53/bbl (US\$16.89/bbl) of SCO in Q4/16.
 - Thermal operations were strong in Q4/16, with production averaging 129,329 bbl/d, within the Company's previously issued quarterly guidance.
 - Kirby South continues to operate near facility capacity, resulting in production of 39,415 bbl/d in Q4/16, an increase of 3% over Q3/16. Including energy costs, operating costs of \$9.56/bbl were achieved in the quarter, supported by a strong SOR of 2.6.
 - Primrose production results of 89,914 bbl/d in Q4/16 were strong, up 38% over Q3/16. As a result, including energy costs, operating costs of \$11.93/bbl were realized in Q4/16, a decrease of 10% from Q3/16 levels.
 - Pelican Lake polymer flood production remained constant at 47,531 bbl/d in Q4/16, flat from Q3/16 levels and a modest decrease of 4% from Q4/15 levels due to natural declines and wellhead cleanouts to improve polymer flood conformance. Operations continued to be optimized, resulting in industry leading operating costs of \$6.57/bbl in Q4/16, a 3% decrease from Q4/15 levels.
 - Within the Company's North America natural gas assets, operations continued to be optimized during the quarter. Operating costs in Q4/16 were \$1.07/Mcf, representing a 9% decrease from Q4/15 and in-line with Q3/16 levels.
 - Operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney continued to impress at \$0.37/Mcfe and \$0.23/Mcfe respectively in Q4/16.
 - The Company's North America E&P crude oil and natural gas drilling program of 87 net wells, excluding strat/service wells, in Q4/16 was in-line with Q3/16 drilling.
 - In the North Sea, the Company's continued focus on production enhancements, increased reliability and water flood optimization, resulted in average production volumes of 24,085 bbl/d in Q4/16, increasing by 4% from Q4/15 levels and 3% from Q3/16 levels. North Sea quarterly crude oil operating costs decreased to \$41.66/bbl, representing a reduction of 27% from Q4/15 levels.
 - Offshore Africa production volumes averaged 21,689 bbl/d in Q4/16. Crude oil operating costs of \$19.05/bbl were realized in Q4/16 representing a 27% reduction from Q4/15. The decrease in operating costs from Q4/15 reflects an increase in production volumes from the infill drilling program completed in Q1/16, timing of liftings from various fields and a focus on effective and efficient operations.

- As previously announced, in Q4/16 the Company successfully completed the disposition of its non-operated 15% ownership in the Cold Lake Pipeline, for approximately \$539 million.
 - In addition to cash proceeds of \$349 million, Canadian Natural retained additional upside potential on the midstream assets through receipt of approximately 6.4 million Inter Pipeline Ltd. ("Inter Pipeline") common shares. As at December 31, 2016, the Inter Pipeline common shares owned were valued at approximately \$190 million.
- Canadian Natural declared a quarterly cash dividend on common shares of C\$0.275 per share payable on April 1, 2017, representing a 10% increase over the previous quarterly dividend of \$0.25 per share. This marks the seventeenth consecutive year of dividend increases since the Company first paid a dividend in 2001 and demonstrates the Board of Directors confidence in the Company's ability to generate sustainable cash flow.
- The Board of Directors of the Corporation also approved today its intention, subject to obtaining regulatory approval, including the approval of the Toronto Stock Exchange ("TSX"), to buy back up to 27,814,309 of its common shares (representing 2.5% of the common shares as at February 28, 2017) through a normal course issuer bid. The purchases will be made over the course of a 12 month period and be subject to the applicable TSX and New York Stock Exchange ("NYSE") rules and securities laws. The timing of and actual number of shares purchased will be determined by the Corporation and be subject to market conditions, share price and regulatory requirements. Shares will be purchased through the facilities of the TSX or other alternative Canadian marketplaces and the NYSE at prevailing market prices at the time of purchase. All purchased shares will be cancelled.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK sector of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, facilitating improved value for the Company's shareholders.

Underpinning this asset base is long-life, low decline production from Horizon Oil Sands mining and upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement costs, and effective and efficient operations means these assets provide substantial and sustainable cash flow throughout the commodity price cycle.

Augmenting this, Canadian Natural maintains a substantial inventory of low capital exposure projects within its conventional asset base. These projects can be executed quickly, and, with the right economic conditions, can provide excellent returns and maximize value for shareholders. Supporting these projects is the Company's undeveloped land base which enables large, repeatable drilling programs; programs that can be optimized over time. Additionally, by owning and operating related infrastructure, Canadian Natural is able to control a major component of its operating cost and minimize production commitments. Low capital exposure projects can typically be easily stopped or started depending upon success, market conditions, or corporate needs.

Canadian Natural's balanced portfolio, built with both long-life, low decline assets and low capital exposure assets, enables effective capital allocation, production growth and value creation.

Drilling Activity

(number of wells)	Year Ended Dec 31			
	2016		2015	
	Gross	Net	Gross	Net
Crude oil	188	174	133	115
Natural gas	11	9	32	19
Dry	7	7	6	6
Subtotal	206	190	171	140
Stratigraphic test / service wells	268	268	206	166
Total	474	458	377	306
Success rate (excluding stratigraphic test / service wells)		96%		96%

- As a result of cost efficiencies and stabilization of commodity prices in the second half of the year, Canadian Natural was able to economically increase its annual drilling program. Annual 2016 drilling increased to 190 net wells, excluding strat/service wells, an increase of 50 net wells from 2015 drilling levels.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs production (bbl/d)	232,019	240,298	259,873	239,912	270,148
Net wells targeting crude oil	75	88	1	170	112
Net successful wells drilled	72	84	1	163	106
Success rate	96%	95%	100%	96%	95%

- Annual production volumes of North America crude oil and NGLs averaged 239,912 bbl/d in 2016, within annual corporate guidance. 2016 production volumes represent a decrease of 11% from 2015 levels as a result of limited drilling activity in 2015 and the first half of 2016. Even with expected production decreases, the Company's effective and efficient operations resulted in operating cost reductions of 9% from 2015 levels.
- North America light crude oil and NGL annual production averaged 87,983 bbl/d, a 4% decrease in 2016 from 2015 levels due to limited drilling activity. Strong annual operating costs of \$13.48/bbl were realized in 2016, a 9% decrease from 2015.
- Pelican Lake operations remained strong with annual production of 47,636 bbl/d and record low annual operating costs of \$6.60/bbl, a 9% reduction from 2015 levels. This low decline, leading edge polymer flood continues to perform well despite limited drilling activity prior to Q4/16 due to capital allocation choices.
- Primary heavy crude oil production decreased year over year to 104,292 bbl/d in 2016, following the Company's proactive decision to reduce its primary heavy crude oil drilling program. Canadian Natural is the industry leading primary heavy crude oil producer and as a result of the continued focus on operations optimization, annual operating costs of \$13.55/bbl were realized, representing a decrease of 10% from 2015 levels.
- The Company's 2017 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range from 232,000 bbl/d - 242,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Bitumen production (bbl/d)	129,329	103,481	135,135	111,046	129,835
Net wells targeting bitumen	8	1	-	9	3
Net successful wells drilled	8	1	-	9	3
Success rate	100%	100%	-	100%	100%

- Thermal in situ oil sands ("thermal in situ") annual production volumes reached 111,046 bbl/d, within corporate guidance, representing an expected 14% decrease from 2015 levels, due to minimal capital allocation to Primrose and the timing of steaming cycles at Primrose.
 - Thermal operations were strong in Q4/16 with average production volumes of 129,329 bbl/d, representing a 25% increase over Q3/16 levels. The increase was driven by another successful production cycle at the Company's Cyclical Steam Stimulation ("CSS") operations at Primrose.
 - At Primrose, strong results from the Company's low pressure steamflood continue. As a result the current production under the steamflood has increased to approximately 32,000 bbl/d representing an increase of 154% from December 2015 volumes of 12,600 bbl/d.
- At Kirby South, the Company's SAGD project, record annual production volumes of 37,714 bbl/d were achieved, a 28% increase over 2015 production volumes.
 - Including energy costs, Kirby South achieved record low annual operating costs of \$9.33/bbl, a decrease of 26% from 2015 levels. Annual SOR continued to be strong in 2016 at 2.6.
- The Company's 2017 thermal in situ annual production guidance remains unchanged and is targeted to range from 105,000 bbl/d - 115,000 bbl/d.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Natural gas production (MMcf/d)	1,578	1,567	1,635	1,622	1,663
Net wells targeting natural gas	4	-	4	9	19
Net successful wells drilled	4	-	4	9	19
Success rate	100%	-	100%	100%	100%

- North America natural gas annual production volumes averaged 1,622 MMcf/d in 2016, a decrease of 2% from 2015 levels. The decrease was mainly due to continued third party facility outages and Nova transportation curtailments which negatively impacted annual production by approximately 100 MMcf/d. Late in 2016, the Company's volumes at the third party gathering and processing facilities began to be brought back on stream.
 - Gains in process optimization continued to be made within the Company's North America natural gas operations, during the year. 2016 operating costs were \$1.12/Mcf, a 12% decrease from 2015 levels.
- 2016 annual operating costs in Canadian Natural's key natural gas areas in the Deep Basin and Montney averaged \$0.47/Mcfe and \$0.23/Mcfe respectively.
- The Company's 2017 total natural gas annual production guidance remains unchanged and is targeted to range from 1,700 MMcf/d to 1,760 MMcf/d.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil production (bbl/d)					
North Sea	24,085	23,450	23,110	23,554	22,216
Offshore Africa	21,689	26,171	24,832	26,096	19,079
Natural gas production (MMcf/d)					
North Sea	44	50	36	38	36
Offshore Africa	24	28	32	31	27
Net wells targeting crude oil	0.9	-	1.2	2.1	5.8
Net successful wells drilled	0.9	-	1.2	2.1	5.8
Success rate	100%	-	100%	100%	100%

- International E&P annual crude oil production volumes were within the Company's production guidance and averaged 49,650 bbl/d, representing a 20% increase over 2015 levels. The year-over-year increase in production reflects the impact of the successful infill drilling program completed at Espoir and Baobab during 2015 and 2016, and substantial gains in production optimization attained in the North Sea, offsetting natural production declines.
 - As a result of capital allocation choices, there has been no drilling activity in the North Sea in the last two years, prior to Q4/16. Due to the Company's continued focus on production enhancements, increased reliability of operations and water flood optimization in the North Sea with production volumes averaged 23,554 bbl/d in 2016, an increase of 6% from 2015 levels. North Sea annual crude oil operating costs averaged \$42.47/bbl in 2016, representing a reduction of 33% from 2015 levels.
 - In addition, effective January 1, 2016, the reduction of the Petroleum Revenue Tax rate from 35% to 0%, and more recently a decrease in the supplementary charge on oil and gas profits from 20% to 10%, represent favorable changes to the tax regime for assets in the North Sea.

- During 2016, at the Company's Offshore Africa assets in Cote d'Ivoire reached annual production of 26,096 bbl/d, representing a 37% increase over 2015 levels. The increase was as a result of strong performance from the Company's successful infill drilling program completed in Q1/16 and continued enhancements in field operations. As a result, operating costs were reduced to \$18.48/bbl, a 45% reduction compared to 2015 levels.
- The Company's 2017 International E&P annual production guidance remains unchanged and is targeted to range from 43,000 bbl/d to 49,000 bbl/d.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Synthetic crude oil production (bbl/d) ⁽¹⁾	178,063	67,586	129,050	123,265	122,911

(1) The Company produces diesel for internal use at Horizon. Fourth quarter 2016 SCO production before royalties excludes 1,619 bbl/d of SCO consumed internally as diesel (third quarter 2016 – 1,464 bbl/d; fourth quarter 2015 – 2,337 bbl/d; year ended December 31, 2016 - 1,966 bbl/d; year ended December 31, 2015 - 2,122 bbl/d).

- Horizon Oil Sands (“Horizon”), Canadian Natural’s world class oil sands mining and upgrading operations, achieved record annual production of 123,265 bbl/d of synthetic crude oil (“SCO”) in 2016, a modest increase over 2015 levels. In October 2016, the Company completed the Horizon Phase 2B expansion and effectively ramped up production to design capacity.
 - Through safe, steady and reliable operations and a strong focus on continuous improvement, the Company realized record low annual average operating costs of \$25.20/bbl, after adjusting for planned downtime in 2016, a 12% reduction from 2015 levels.
 - Strong production has continued at Horizon with December, January and February production levels of approximately 184,000 bbl/d, 195,000 bbl/d and 202,600 bbl/d of SCO, respectively.
 - During 2016, Canadian Natural continued to advance the Horizon Phase 3 expansion. The final component of the Company's transition to a long-life, low decline asset base is progressing as planned, reaching 89% physical completion as at December 31, 2016. The start-up of Phase 3 is targeted for Q4/17 and is targeted to add incremental production capacity of 80,000 bbl/d of SCO. With the completion of the Horizon Phase 3 expansion, operating costs are targeted to make a further step change downward from current levels.
 - In 2016, Horizon project capital expenditures totaled \$1.920 billion, below the Company's 2015 estimate and the 2016 capital budget, impressive results given the challenges faced in the region. Additionally, in 2017, Horizon project capital expenditures are targeted to be approximately \$1.055 billion to complete the Phase 3 expansion, which remains on budget and on schedule for Q4/17 start-up.
- Directive 85 (formerly Directive 74) of the Horizon expansion remains on track and was 68% physically complete as at December 31, 2016. This project includes research into tailings management and technological investment.
- Continued progress is being made on the Company's review of debottleneck options at Horizon. The Company is presently reviewing a debottlenecking option that is targeted to add 5,000 bbl/d - 15,000 bbl/d of SCO with targeted project capital of \$70 million. As previously announced, the decision to go forward with this project is targeted for Q2/17.
- The Company's 2017 Horizon annual production guidance remains unchanged and is targeted to range from 170,000 bbl/d to 184,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGL pricing					
WTI benchmark price (US\$/bbl) ⁽¹⁾	\$ 49.33	\$ 44.94	\$42.17	\$ 43.37	\$ 48.76
WCS blend differential from WTI (%) ⁽²⁾	30%	30%	34%	32%	28%
SCO price (US\$/bbl)	\$ 48.91	\$ 45.63	\$ 42.77	\$ 43.94	\$ 48.59
Condensate benchmark pricing (US\$/bbl)	\$ 48.37	\$ 43.05	\$ 41.67	\$ 42.51	\$ 47.34
Average realized pricing before risk management (C\$/bbl) ⁽³⁾	\$ 45.00	\$ 39.66	\$ 33.90	\$ 36.93	\$ 41.13
Natural gas pricing					
AECO benchmark price (C\$/GJ)	\$ 2.67	\$ 2.08	\$ 2.51	\$ 1.98	\$ 2.62
Average realized pricing before risk management (C\$/Mcf)	\$ 3.14	\$ 2.44	\$ 2.96	\$ 2.32	\$ 3.16

(1) West Texas Intermediate ("WTI").

(2) Western Canadian Select ("WCS").

(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

- WTI averaged US\$49.33/bbl for Q4/16, a increase of 17% from US\$42.17/bbl in Q4/15 and an increase of 10% from US\$44.94/bbl in Q3/16. WTI pricing for the year ended December 31, 2016 continued to reflect volatility in supply and demand factors, geopolitical events and OPEC and non-OPEC countries decision to cut production in Q4/16.
- The WCS differential to WTI averaged US\$13.91/bbl (32%) in 2016 compared to US\$13.51/bbl (28%) in 2015. In Q4/16, the WCS Heavy Differential averaged US\$14.59/bbl (30%) compared with US\$14.48/bbl (34%) and US\$13.49/bbl (30%) in Q4/15 and Q3/16 respectively. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.
- Canadian Natural contributed approximately 210,000 bbl/d of its heavy crude oil stream to the WCS blend in 2016. The Company remains the largest contributor to the WCS blend, accounting for 49% of the total blend.
- SCO pricing averaged US\$43.94/bbl during 2016 compared to US\$48.59/bbl in 2015, a decrease of 10%. The SCO price averaged US\$48.91/bbl for Q4/16, a increase from US\$42.77/bbl for Q4/15, and US\$45.63/bbl for Q3/16, representing increases of 14% and 7% respectively. The fluctuations in SCO pricing for Q4/16 and 2016 annual from comparable periods were primarily due to changes in WTI benchmark pricing.
- AECO natural gas prices in 2016 averaged \$1.98/GJ, from \$2.62/GJ in 2015 representing a 24% decrease. AECO pricing averaged \$2.67/GJ for Q4/16, an increase of 6% from \$2.51/GJ for Q4/15, and an increase of 28% from \$2.08/GJ for Q3/16. The decrease in natural gas prices for 2016 compared with 2015 was primarily due to warmer than normal winter temperatures in 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season which resulted in weaker prices during storage injection. The increase in natural gas prices in Q4/16 compared with Q3/16 and Q4/15 was primarily due to lower US natural gas production. Reduced supply resulted in natural gas storage inventories returning to historically normal levels by the end of 2016.
- The North West Redwater refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by adding 50,000 bbl/d of bitumen conversion capacity in Alberta which will help reduce pricing volatility in all Western Canadian heavy crude oil. The Company has a 50% interest in the North West Redwater Partnership. For project updates, please refer to: <https://nwrsturgeonrefinery.com/whats-happening/news/>.

FINANCIAL REVIEW

The Company continues to implement proven strategies and its disciplined approach to capital allocation. As a result, the financial position of Canadian Natural remains strong. Canadian Natural's cash flow generation, credit facilities, US commercial paper program, diverse asset base and related flexible capital expenditure programs all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production of 805,782 BOE/d in 2016, with approximately 96% of total production located in G7 countries.
- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2016, the Company had in place bank credit facilities of \$7.4 billion, of which \$3.0 billion was available, an increase from \$2.35 billion as at September 30, 2016. Balance sheet strength continues to be a focus of the Company with debt to book capitalization of 39% at December 31, 2016, within the Company's targeted operating range.
- Subsequent to December 31, 2016, Moody's Investors Service, Inc. adjusted the Company's credit rating outlook from negative to stable on the Company's investment grade credit rating.
- On August 9, 2016, the Company successfully issued its largest single tranche medium-term note transaction in Canada of \$1.0 billion. The net proceeds from the five and a half year 3.31% notes were used to repay credit facilities, thereby generating additional liquidity for the Company.
- In addition to its strong cash flow and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at December 31, 2016, these financial levers include the Company's investment in PrairieSky and Inter Pipeline with approximate values of \$720 million and \$190 million respectively, and cross currency swaps maturing after 2020 with an approximate value of \$330 million. Additionally, the Company could monetize its third party royalty volumes of up to approximately 1,000 BOE/d.
- As previously announced, in Q4/16 the Company successfully completed the disposition of its non-core and non-operated 15% ownership in the Cold Lake Pipeline, for approximately \$539 million.
 - In addition to cash proceeds of \$349 million, Canadian Natural retained additional upside potential on the midstream assets through receipt of approximately 6.4 million Inter Pipeline common shares. As at December 31, 2016, the Inter Pipeline common shares owned were valued at approximately \$190 million.
- At December 31, 2016, 50,000 GJ/d of natural gas volumes were hedged using AECO swaps for January 2017 to October 2017. Subsequent to year end, 50,000 bbl/d of crude oil volumes were hedged for February 2017 through December 2017 and 17,500 bbl/d of crude oil volumes were hedged for March 2017 through December 2017, both using WTI costless collars. For full hedging disclosure please see the Company's website.
- The Company remained focused on returns to shareholders in 2016 increasing dividends by approximately 9% to \$0.25/share in Q4/16, reflecting the Board of Director's confidence in the Company's cash flow. In addition, the Company distributed 21.8 million PrairieSky common shares to shareholders as a return of capital in Q2/16 valued at approximately \$546 million.
- Canadian Natural declared a quarterly cash dividend on common shares of C\$0.275 per share payable on April 1, 2017, representing a 10% increase over the previous quarterly dividend of \$0.25 per share. This marks the seventeenth consecutive year of dividend increases since the Company first paid a dividend in 2001 and demonstrates the Board of Directors confidence in the Company's ability to generate sustainable cash flow.
- The Board of Directors of the Corporation also approved today its intention, subject to obtaining regulatory approval, including the approval of the Toronto Stock Exchange ("TSX"), to buy back up to 27,814,309 of its common shares (representing 2.5% of the common shares as at February 28, 2017) through a normal course issuer bid. The purchases will be made over the course of a 12 month period and be subject to the applicable TSX and New York Stock Exchange ("NYSE") rules and securities laws. The timing of and actual number of shares purchased will be determined by the Corporation and be subject to market conditions, share price and regulatory requirements. Shares will be purchased through the facilities of the TSX or other alternative Canadian marketplaces and the NYSE at prevailing market prices at the time of purchase. All purchased shares will be canceled.

OUTLOOK

The Company forecasts annual 2017 production levels to average between 550,000 and 590,000 bbl/d of crude oil and NGLs and between 1,700 and 1,760 MMcf/d of natural gas, before royalties. Q1/17 production guidance before royalties is forecast to average between 591,000 and 615,000 bbl/d of crude oil and NGLs and between 1,700 and 1,740 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Canadian Natural's annual 2017 capital expenditures are targeted to be approximately \$3.9 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A"), constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansions, Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas and natural gas liquids ("NGLs") reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital and operating costs); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or Management's estimates or opinions change.

Management's Discussion and Analysis

This MD&A of the financial condition and results of operations of the Company should be read in conjunction with the unaudited interim consolidated financial statements for the three months and year ended December 31, 2016 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the period ended December 31, 2016 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

A Barrel of Oil Equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending costs and exclude the effect of risk management activities. Production on an "after royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2016 in relation to the comparable periods in 2015 and the third quarter of 2016. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2015, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 1, 2017.

FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Product sales	\$ 3,672	\$ 2,477	\$ 2,963	\$ 11,098	\$ 13,167
Net earnings (loss)	\$ 566	\$ (326)	\$ 131	\$ (204)	\$ (637)
Per common share – basic	\$ 0.51	\$ (0.29)	\$ 0.12	\$ (0.19)	\$ (0.58)
– diluted	\$ 0.51	\$ (0.29)	\$ 0.12	\$ (0.19)	\$ (0.58)
Adjusted net earnings (loss) from operations ⁽¹⁾	\$ 439	\$ (355)	\$ (49)	\$ (669)	\$ 263
Per common share – basic	\$ 0.40	\$ (0.32)	\$ (0.04)	\$ (0.61)	\$ 0.24
– diluted	\$ 0.40	\$ (0.32)	\$ (0.04)	\$ (0.61)	\$ 0.24
Funds flow from operations ⁽²⁾	\$ 1,677	\$ 1,021	\$ 1,379	\$ 4,293	\$ 5,785
Per common share – basic	\$ 1.52	\$ 0.93	\$ 1.26	\$ 3.90	\$ 5.29
– diluted	\$ 1.50	\$ 0.92	\$ 1.26	\$ 3.89	\$ 5.28
Net capital expenditures	\$ 411	\$ 1,185	\$ (96)	\$ 3,794	\$ 3,853

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings (loss) from operations. The reconciliation "Adjusted Net Earnings (Loss) from Operations" presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Funds flow from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for certain non-cash items and current income tax on disposition of properties. The Company evaluates its performance based on funds flow from operations. The Company considers funds flow from operations a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Funds Flow from Operations, as Reconciled to Net Earnings (Loss)" presented in this MD&A, includes certain non-cash items that are disclosed in the Company's financial results as presented in the Company's consolidated Statements of Cash Flows. Funds flow from operations may not be comparable to similar measures presented by other companies.

Funds flow from operations can also be derived by adjusting the GAAP measure Cash Flows from Operating Activities presented in the Company's consolidated Statements of Cash Flows for the net change in non-cash working capital, and abandonment and other expenditures. Accordingly, the Company has provided a second reconciliation, "Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities" in this MD&A.

Adjusted Net Earnings (Loss) from Operations

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net earnings (loss) as reported	\$ 566	\$ (326)	\$ 131	\$ (204)	\$ (637)
Share-based compensation, net of tax ⁽¹⁾	42	74	56	355	(46)
Unrealized risk management (gain) loss, net of tax ⁽²⁾	(7)	11	128	21	275
Unrealized foreign exchange loss (gain), net of tax ⁽³⁾	162	39	170	(93)	858
(Gain) loss from investments, net of tax ⁽⁴⁾⁽⁵⁾	(106)	(46)	23	(299)	55
Gain on disposition of properties and corporate acquisitions and dispositions, net of tax ⁽⁶⁾	(218)	—	(627)	(241)	(663)
Derecognition of exploration and evaluation assets, net of tax ⁽⁷⁾	—	—	70	13	70
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities ⁽⁸⁾	—	(107)	—	(221)	351
Adjusted net earnings (loss) from operations	\$ 439	\$ (355)	\$ (49)	\$ (669)	\$ 263

(1) The Company's employee stock option plan provides for a cash payment option. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are capitalized to Oil Sands Mining and Upgrading construction costs.

(2) Derivative financial instruments are recorded at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings (loss). The amounts ultimately realized may be materially different than reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange.

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates, partially offset by the impact of cross currency swaps, and are recognized in net earnings (loss).

(4) The Company's investment in the 50% owned North West Redwater Partnership ("Redwater Partnership") is accounted for using the equity method of accounting. Included in the non-cash (gain) loss from investments is the Company's pro rata share of the Redwater Partnership's accounting (gain) loss for the period.

(5) The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") have been accounted for at fair value through profit and loss and are remeasured each period with changes in fair value recognized in net earnings (loss).

(6) During the fourth quarter of 2016, the Company recorded a pre and after-tax gain of \$218 million on the disposition of Midstream property, plant and equipment. During the first quarter of 2016, the Company recorded a pre-tax gain of \$32 million (\$23 million after-tax) on the disposition of certain exploration and evaluation assets. During the fourth quarter of 2015, the Company recorded a pre-tax gain of \$690 million (\$627 million after-tax) related to the disposition of a number of North America royalty income assets. During the third quarter of 2015, the Company recorded a pre-tax gain of \$49 million (\$36 million after-tax) related to the disposition of a number of North America crude oil and natural gas properties.

(7) In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized \$18 million (\$13 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense. In connection with the Company's notice of withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa in the fourth quarter of 2015, the Company derecognized \$96 million (\$70 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

(8) In the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of \$107 million. During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of \$114 million. During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of \$579 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of \$228 million.

Funds Flow from Operations, as Reconciled to Net Earnings (Loss)⁽¹⁾

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net earnings (loss)	\$ 566	\$ (326)	\$ 131	\$ (204)	\$ (637)
Non-cash items:					
Depletion, depreciation and amortization	1,249	1,216	1,472	4,858	5,483
Share-based compensation	42	74	56	355	(46)
Asset retirement obligation accretion	35	36	43	142	173
Unrealized risk management (gain) loss	(7)	10	174	25	374
Unrealized foreign exchange loss (gain)	162	39	170	(93)	858
(Gain) loss from investments	(106)	(46)	23	(299)	55
Deferred income tax (recovery) expense	(46)	18	(33)	(241)	231
Gain on disposition of properties and corporate acquisitions and dispositions	(218)	—	(690)	(250)	(739)
Current income tax on disposition of properties	—	—	33	—	33
Funds flow from operations	\$ 1,677	\$ 1,021	\$ 1,379	\$ 4,293	\$ 5,785

(1) Funds flow from operations was previously referred to as cash flow from operations.

Funds Flow from Operations, as Reconciled to Cash Flows from Operating Activities

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Cash flows from operating activities	\$ 1,255	\$ 899	\$ 1,485	\$ 3,452	\$ 5,632
Net change in non-cash working capital	317	14	(314)	542	(239)
Abandonment expenditures	35	122	105	267	370
Other	70	(14)	103	32	22
Funds flow from operations	\$ 1,677	\$ 1,021	\$ 1,379	\$ 4,293	\$ 5,785

SUMMARY OF CONSOLIDATED NET EARNINGS (LOSS) AND FUNDS FLOW FROM OPERATIONS

The net loss for the year ended December 31, 2016 was \$204 million compared with a net loss of \$637 million for the year ended December 31, 2015. The net loss for the year ended December 31, 2016 included net after-tax income of \$465 million compared with net after-tax expenses of \$900 million for the year ended December 31, 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on disposition of properties and corporate acquisitions and dispositions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the year ended December 31, 2016 was \$669 million compared with adjusted net earnings of \$263 million for the year ended December 31, 2015.

Net earnings for the fourth quarter of 2016 were \$566 million compared with net earnings of \$131 million for the fourth quarter of 2015 and a net loss of \$326 million for the third quarter of 2016. Net earnings for the fourth quarter of 2016 included net after-tax income of \$127 million compared with net after-tax income of \$180 million for the fourth quarter of 2015 and net after-tax income of \$29 million for the third quarter of 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gains on disposition of properties and corporate acquisitions and dispositions, derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2016 were \$439 million compared with an adjusted net loss of \$49 million for the fourth quarter of 2015 and an adjusted net loss of \$355 million for the third quarter of 2016.

The decrease in adjusted net earnings (loss) for the year ended December 31, 2016 from the year ended December 31, 2015 was primarily due to:

- lower crude oil and NGLs sales volumes in the North America segment;
- lower natural gas netbacks in the Exploration and Production segments;
- lower crude oil and NGLs netbacks in the North America segment; and
- lower realized risk management gains;

partially offset by:

- higher crude oil and NGLs sales volumes in the Offshore Africa segment; and
- the weakening of the Canadian dollar.

The increase in adjusted net earnings (loss) for the fourth quarter of 2016 from the fourth quarter of 2015 and the third quarter of 2016 was primarily due to:

- record high SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher SCO realized prices in the Oil Sands Mining and Upgrading segment;

partially offset by:

- lower realized risk management gains.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates are expected to continue to contribute to significant volatility in consolidated net earnings (loss) and are discussed in detail in the relevant sections of this MD&A.

Funds flow from operations for the year ended December 31, 2016 was \$4,293 million compared with \$5,785 million for the year ended December 31, 2015. Funds flow from operations for the fourth quarter of 2016 was \$1,677 million compared with \$1,379 million for the fourth quarter of 2015 and \$1,021 million for the third quarter of 2016. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss), as well as due to the impact of fluctuations in cash taxes and depletion, depreciation and amortization.

Total production before royalties for the fourth quarter of 2016 of 859,577 BOE/d was comparable to 855,800 BOE/d for the fourth quarter of 2015 and increased 17% from 735,212 BOE/d for the third quarter of 2016.

SUMMARY OF QUARTERLY RESULTS

The following is a summary of the Company's quarterly results for the eight most recently completed quarters:

(\$ millions, except per common share amounts)	Dec 31 2016	Sep 30 2016	Jun 30 2016	Mar 31 2016
Product sales	\$ 3,672	\$ 2,477	\$ 2,686	\$ 2,263
Net earnings (loss)	\$ 566	\$ (326)	\$ (339)	\$ (105)
Net earnings (loss) per common share				
– basic	\$ 0.51	\$ (0.29)	\$ (0.31)	\$ (0.10)
– diluted	\$ 0.51	\$ (0.29)	\$ (0.31)	\$ (0.10)
(\$ millions, except per common share amounts)	Dec 31 2015	Sep 30 2015	Jun 30 2015	Mar 31 2015
Product sales	\$ 2,963	\$ 3,316	\$ 3,662	\$ 3,226
Net earnings (loss)	\$ 131	\$ (111)	\$ (405)	\$ (252)
Net earnings (loss) per common share				
– basic	\$ 0.12	\$ (0.10)	\$ (0.37)	\$ (0.23)
– diluted	\$ 0.12	\$ (0.10)	\$ (0.37)	\$ (0.23)

Volatility in the quarterly net earnings (loss) over the eight most recently completed quarters was primarily due to:

- **Crude oil pricing** – The impact of shale oil production in North America, fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the WCS Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma (“WTI”) in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the reduction in the Company’s drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon, and the impact of the drilling program in Côte d’Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, shut-in production due to third party pipeline restrictions and related pricing impacts and an outage at a third party processing facility, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, turnarounds at Horizon and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, fluctuations in international sales volumes subject to higher depletion rates, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark - to - market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on disposition of properties and investments** – Fluctuations due to the recognition of gains on disposition of properties in the various periods and fair value changes in the investment in PrairieSky and Inter Pipeline shares.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
WTI benchmark price (US\$/bbl)	\$ 49.33	\$ 44.94	\$ 42.17	\$ 43.37	\$ 48.76
Dated Brent benchmark price (US\$/bbl)	\$ 50.27	\$ 45.76	\$ 43.59	\$ 43.96	\$ 52.40
WCS blend differential from WTI (US\$/bbl)	\$ 14.59	\$ 13.49	\$ 14.48	\$ 13.91	\$ 13.51
WCS blend differential from WTI (%)	30%	30%	34%	32%	28%
SCO price (US\$/bbl)	\$ 48.91	\$ 45.63	\$ 42.77	\$ 43.94	\$ 48.59
Condensate benchmark price (US\$/bbl)	\$ 48.37	\$ 43.05	\$ 41.67	\$ 42.51	\$ 47.34
NYMEX benchmark price (US\$/MMBtu)	\$ 2.99	\$ 2.81	\$ 2.28	\$ 2.45	\$ 2.67
AECO benchmark price (C\$/GJ)	\$ 2.67	\$ 2.08	\$ 2.51	\$ 1.98	\$ 2.62
US/Canadian dollar average exchange rate (US\$)	\$ 0.7496	\$ 0.7663	\$ 0.7489	\$ 0.7548	\$ 0.7820

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("Brent") indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. For the three months and year ended December 31, 2016, realized prices continued to be supported by the weaker Canadian dollar, as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US\$43.37 per bbl for the year ended December 31, 2016, a decrease of 11% from US\$48.76 per bbl for the year ended December 31, 2015. WTI averaged US\$49.33 per bbl for the fourth quarter of 2016, an increase of 17% from US\$42.17 per bbl for the fourth quarter of 2015, and an increase of 10% from \$44.94 per bbl for the third quarter of 2016.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US\$43.96 per bbl for the year ended December 31, 2016, a decrease of 16% from US\$52.40 per bbl for the year ended December 31, 2015. Brent averaged US\$50.27 per bbl for the fourth quarter of 2016, an increase of 15% from US\$43.59 per bbl for the fourth quarter of 2015, and an increase of 10% from \$45.76 per bbl for the third quarter of 2016.

WTI and Brent pricing for the three months and year ended December 31, 2016 continued to reflect volatility in supply and demand factors and geopolitical events. The OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries contributed to an increase in fourth quarter pricing from comparable quarters.

The WCS Heavy Differential averaged 32% for the year ended December 31, 2016, compared with 28% for the year ended December 31, 2015. The WCS Heavy Differential averaged 30% for the fourth quarter of 2016 compared with 34% for the fourth quarter of 2015 and 30% for the third quarter of 2016. Fluctuations in the WCS Heavy Differential reflected seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US\$43.94 per bbl for the year ended December 31, 2016, a decrease of 10% from US\$48.59 per bbl for the year ended December 31, 2015. The SCO price averaged US\$48.91 per bbl for the fourth quarter of 2016, an increase of 14% from \$42.77 per bbl for the fourth quarter of 2015, and an increase of 7% from US\$45.63 per bbl for the third quarter of 2016. The fluctuations in SCO pricing for the three months and year ended December 31, 2016 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US\$2.45 per MMBtu for the year ended December 31, 2016, a decrease of 8% from US\$2.67 per MMBtu for the year ended December 31, 2015. NYMEX natural gas prices averaged US\$2.99 per MMBtu for the fourth quarter of 2016, an increase of 31% from \$2.28 per MMBtu for the fourth quarter of 2015, and an increase of 6% from US\$2.81 per MMBtu for the third quarter of 2016.

AECO natural gas prices averaged \$1.98 per GJ for the year ended December 31, 2016, a decrease of 24% from \$2.62 per GJ for the year ended December 31, 2015. AECO natural gas prices averaged \$2.67 per GJ for the fourth quarter of 2016, an increase of 6% from \$2.51 per GJ for the fourth quarter of 2015, and an increase of 28% from \$2.08 per GJ for the third quarter of 2016.

The decrease in natural gas prices for 2016 compared with 2015 was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

The increase in natural gas prices in the fourth quarter of 2016 compared with the third quarter of 2016 and the fourth quarter of 2015 was primarily due to lower US natural gas production. Reduced supply resulted in natural gas storage inventories returning to historically normal levels by the end of 2016.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	361,348	343,779	395,008	350,958	399,982
North America – Oil Sands Mining and Upgrading ⁽¹⁾	178,063	67,586	129,050	123,265	122,911
North Sea	24,085	23,450	23,110	23,554	22,216
Offshore Africa	21,689	26,171	24,832	26,096	19,079
	585,185	460,986	572,000	523,873	564,188
Natural gas (MMcf/d)					
North America	1,578	1,567	1,635	1,622	1,663
North Sea	44	50	36	38	36
Offshore Africa	24	28	32	31	27
	1,646	1,645	1,703	1,691	1,726
Total barrels of oil equivalent (BOE/d)	859,577	735,212	855,800	805,782	851,901
Product mix					
Light and medium crude oil and NGLs	15%	19%	16%	17%	16%
Pelican Lake heavy crude oil	6%	7%	6%	6%	6%
Primary heavy crude oil	11%	14%	14%	13%	15%
Bitumen (thermal oil)	15%	14%	16%	14%	15%
Synthetic crude oil ⁽¹⁾	21%	9%	15%	15%	14%
Natural gas	32%	37%	33%	35%	34%
Percentage of gross revenue ^{(1) (2)} (excluding Midstream revenue)					
Crude oil and NGLs	85%	83%	82%	85%	82%
Natural gas	15%	17%	18%	15%	18%

(1) Fourth quarter 2016 SCO production before royalties excludes 1,619 bbl/d of SCO consumed internally as diesel (third quarter 2016 – 1,464 bbl/d; fourth quarter 2015 – 2,337 bbl/d; year ended December 31, 2016 - 1,966 bbl/d; year ended December 31, 2015 - 2,122 bbl/d).

(2) Net of blending costs and excluding risk management activities.

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	315,090	305,189	345,027	311,059	350,451
North America – Oil Sands Mining and Upgrading	175,860	67,008	127,968	122,258	121,208
North Sea	24,034	23,404	23,054	23,497	22,164
Offshore Africa	20,730	25,061	23,620	24,995	18,209
	535,714	420,662	519,669	481,809	512,032
Natural gas (MMcf/d)					
North America	1,480	1,497	1,568	1,559	1,606
North Sea	44	50	36	38	36
Offshore Africa	23	27	30	30	25
	1,547	1,574	1,634	1,627	1,667
Total barrels of oil equivalent (BOE/d)	793,483	682,944	792,083	752,974	789,799

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), SCO and natural gas.

Crude oil and NGLs production for the year ended December 31, 2016 decreased 7% to 523,873 bbl/d from 564,188 bbl/d for the year ended December 31, 2015. Crude oil and NGL production for the fourth quarter of 2016 of 585,185 bbl/d increased by 2% from 572,000 bbl/d for the fourth quarter of 2015, and increased by 27% from 460,986 bbl/d in the third quarter of 2016. The decrease in crude oil and NGL production for the year ended December 31, 2016 from 2015 was primarily due to lower drilling activity and natural field declines in North America, partially offset by increased production in the International segments. The increase in crude oil and NGLs production for the fourth quarter of 2016 from the fourth quarter of 2015 and the third quarter of 2016 primarily reflected new Phase 2B production at Horizon following the completion of the planned major turnaround in the third quarter of 2016, as well as the impact of the cyclic nature of thermal production at Primrose.

Annual 2016 crude oil and NGLs production was within the Company's previously issued guidance of 514,000 to 563,000 bbl/d of crude oil and NGLs. For 2017, annual production guidance is targeted to average between 550,000 and 590,000 bbl/d of crude oil and NGLs. First quarter 2017 production guidance is targeted to average between 591,000 and 615,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2016 decreased 2% to 1,691 MMcf/d from 1,726 MMcf/d for the year ended December 31, 2015. Natural gas production for the fourth quarter of 2016 of 1,646 MMcf/d decreased 3% from 1,703 MMcf/d for the fourth quarter of 2015, and was comparable with the third quarter of 2016. Natural gas production for the three months and year ended December 31, 2016 decreased from the comparable periods in 2015 as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. Due to the delay, the Company only averaged 76 MMcf/d of net sales volumes through the facility during the fourth quarter of 2016 compared to the Company's operated sales capacity of approximately 176 MMcf/d. Accordingly, fourth quarter 2016 production was approximately 100 MMcf/d less than it otherwise would have been had the facility been in full operation. Additionally, during the fourth quarter of 2016, third party pipeline transportation restrictions were 45 MMcf/d. On an annual basis, North America natural gas production volumes were impacted by approximately 70 MMcf/d due to the third party gathering system and facility outage and 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end.

Annual 2016 natural gas production was below the Company's previously issued guidance of 1,705 to 1,735 MMcf/d of natural gas. Annual natural gas production guidance for 2017 is targeted to average between 1,700 and 1,760 MMcf/d. First quarter 2017 natural gas production guidance is targeted to average between 1,700 and 1,740 MMcf/d, an increase of approximately 74 MMcf/d compared to the fourth quarter of 2016 volumes at the midpoint of guidance.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2016 decreased 12% to average 350,958 bbl/d from 399,982 bbl/d for the year ended December 31, 2015. North America crude oil and NGLs production for the fourth quarter of 2016 decreased 9% to 361,348 bbl/d from 395,008 bbl/d for the fourth quarter of 2015, and increased 5% from 343,779 bbl/d for the third quarter of 2016. The fluctuations in production for the three months and year ended December 31, 2016 from comparable periods primarily reflected lower drilling activity, natural field declines and the cyclic nature of thermal oil production at Primrose. Annual 2016 production of crude oil and NGLs was within the Company's previously issued guidance of 345,000 to 375,000 bbl/d. Annual production guidance for 2017 is targeted to average between 337,000 and 357,000 bbl/d of crude oil and NGLs. First quarter 2017 production guidance is targeted to average between 356,000 and 368,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2016 decreased 2% to average 1,622 MMcf/d from 1,663 MMcf/d for the year ended December 31, 2015. Natural gas production for the fourth quarter of 2016 decreased 3% to 1,578 MMcf/d from 1,635 MMcf/d for the fourth quarter of 2015, and was comparable with the third quarter of 2016. Natural gas production for the three months and year ended December 31, 2016 decreased from the comparable periods in 2015 as a result of flood damage to a third party gathering system and facility in June 2016, together with the delay in the repair and reinstatement of full processing capacity. Due to the delay, the Company only averaged 76 MMcf/d of net sales volumes through the facility during the fourth quarter of 2016 compared to the Company's operated sales capacity of approximately 176 MMcf/d. Accordingly, fourth quarter 2016 production was approximately 100 MMcf/d less than it otherwise would have been had the facility been in full operation. Additionally, during the fourth quarter of 2016, third party pipeline transportation restrictions were 45 MMcf/d. On an annual basis, North America natural gas production volumes were impacted by approximately 70 MMcf/d due to the third party gathering system and facility outage and 31 MMcf/d due to third party transportation restrictions. The Company's sales volumes at the third party facility have increased subsequent to year end.

North America – Oil Sands Mining and Upgrading

SCO production for the year ended December 31, 2016 of 123,265 bbl/d was comparable with 122,911 bbl/d for the year ended December 31, 2015. SCO production for the fourth quarter of 2016 increased 38% to average a record 178,063 bbl/d compared with 129,050 bbl/d for the fourth quarter of 2015 and increased 163% from 67,586 bbl/d for the third quarter of 2016. The increase in production for the fourth quarter of 2016 from the comparable periods primarily reflected new Phase 2B production following the completion of the planned major turnaround in the third quarter of 2016.

Annual 2016 production of SCO was within the Company's previously issued guidance of 120,000 to 132,000 bbl/d. Annual production guidance for 2017 is targeted to average between 170,000 and 184,000 bbl/d of SCO, including the impact of planned tie-ins and turnarounds. First quarter 2017 production guidance is targeted to average between 192,000 and 200,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2016 increased 6% to 23,554 bbl/d from 22,216 bbl/d for the year ended December 31, 2015. North Sea crude oil production for the fourth quarter of 2016 increased 4% to 24,085 bbl/d from 23,110 bbl/d for the fourth quarter of 2015 and increased 3% from 23,450 bbl/d for the third quarter of 2016. The increase in production for the three months and year ended December 31, 2016 from comparable periods was due to successful production optimization, more than offsetting natural field declines.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2016 increased 37% to 26,096 bbl/d from 19,079 bbl/d for the year ended December 31, 2015. Offshore Africa crude oil production for the fourth quarter of 2016 decreased 13% to 21,689 bbl/d from 24,832 bbl/d for the fourth quarter of 2015, and decreased 17% from 26,171 bbl/d for the third quarter of 2016. Production volumes increased for the year ended December 31, 2016 from the comparable period in 2015, reflecting the impact of additional wells coming on stream at the Espoir and Baobab fields during 2015 and 2016, partially offset by natural field declines and unplanned downtime. The decrease in the fourth quarter of 2016 from the fourth quarter of 2015 and the third quarter of 2016 primarily reflected natural field declines and planned and unplanned production downtime.

International Guidance

Annual International crude oil production was within the Company's previously issued guidance of 49,000 to 56,000 bbl/d. Annual production guidance for 2017 is targeted to average between 43,000 and 49,000 bbl/d of crude oil. First quarter 2017 production guidance is targeted to average between 43,000 and 47,000 bbl/d of crude oil.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when title transfers to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes that were stored in various storage facilities or FPSOs, as follows:

(bbl)	Dec 31 2016	Sep 30 2016	Dec 31 2015
North Sea	987,316	940,089	835,806
Offshore Africa	1,126,999	1,587,341	1,271,170
	2,114,315	2,527,430	2,106,976

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
Sales price ⁽²⁾	\$ 45.00	\$ 39.66	\$ 33.90	\$ 36.93	\$ 41.13
Transportation	2.70	2.51	2.61	2.61	2.60
Realized sales price, net of transportation	42.30	37.15	31.29	34.32	38.53
Royalties	4.62	3.48	3.49	3.40	4.30
Production expense	14.28	13.85	14.26	14.10	15.74
Netback	\$ 23.40	\$ 19.82	\$ 13.54	\$ 16.82	\$ 18.49
Natural gas (\$/Mcf) ⁽¹⁾					
Sales price ⁽²⁾	\$ 3.14	\$ 2.44	\$ 2.96	\$ 2.32	\$ 3.16
Transportation	0.34	0.40	0.38	0.33	0.38
Realized sales price, net of transportation	2.80	2.04	2.58	1.99	2.78
Royalties	0.17	0.09	0.10	0.09	0.10
Production expense	1.15	1.08	1.22	1.18	1.34
Netback	\$ 1.48	\$ 0.87	\$ 1.26	\$ 0.72	\$ 1.34
Barrels of oil equivalent (\$/BOE) ⁽¹⁾					
Sales price ⁽²⁾	\$ 34.54	\$ 29.39	\$ 27.79	\$ 27.58	\$ 32.60
Transportation	2.46	2.51	2.59	2.44	2.56
Realized sales price, net of transportation	32.08	26.88	25.20	25.14	30.04
Royalties	3.16	2.27	2.38	2.21	2.85
Production expense	11.34	10.83	11.55	11.18	12.70
Netback	\$ 17.58	\$ 13.78	\$ 11.27	\$ 11.75	\$ 14.49

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (\$/bbl) ⁽¹⁾⁽²⁾					
North America	\$ 42.56	\$ 36.84	\$ 31.51	\$ 34.31	\$ 38.96
North Sea	\$ 63.68	\$ 60.00	\$ 57.50	\$ 55.91	\$ 65.13
Offshore Africa	\$ 61.29	\$ 58.30	\$ 53.37	\$ 54.96	\$ 63.13
Company average	\$ 45.00	\$ 39.66	\$ 33.90	\$ 36.93	\$ 41.13
Natural gas (\$/Mcf) ⁽¹⁾⁽²⁾					
North America	\$ 2.97	\$ 2.30	\$ 2.73	\$ 2.15	\$ 2.91
North Sea	\$ 7.75	\$ 5.27	\$ 9.53	\$ 6.62	\$ 9.66
Offshore Africa	\$ 5.75	\$ 5.39	\$ 7.63	\$ 6.13	\$ 9.53
Company average	\$ 3.14	\$ 2.44	\$ 2.96	\$ 2.32	\$ 3.16
Company average (\$/BOE) ⁽¹⁾⁽²⁾	\$ 34.54	\$ 29.39	\$ 27.79	\$ 27.58	\$ 32.60

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North America

North America realized crude oil prices decreased 12% to \$34.31 per bbl for the year ended December 31, 2016 from \$38.96 per bbl for the year ended December 31, 2015. North America realized crude oil prices averaged \$42.56 per bbl for the fourth quarter of 2016, an increase of 35% compared with \$31.51 per bbl for the fourth quarter of 2015 and an increase of 16% compared with \$36.84 per bbl for the third quarter of 2016. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2016 from the comparable periods were primarily due to WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2016, contributed approximately 214,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 26% to average \$2.15 per Mcf for the year ended December 31, 2016 from \$2.91 per Mcf for the year ended December 31, 2015. North America realized natural gas prices increased 9% to average \$2.97 per Mcf for the fourth quarter of 2016 compared with \$2.73 per Mcf for the fourth quarter of 2015, and increased 29% compared with \$2.30 per Mcf for the third quarter of 2016. The decrease in natural gas prices per Mcf for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to warmer than normal winter temperatures in the first quarter of 2016. US natural gas inventories were at near record high levels at the end of the 2015/2016 winter season, which resulted in weaker prices during storage injection.

The increase in realized natural gas prices for the fourth quarter of 2016 compared with the fourth quarter of 2015 and third quarter of 2016 was primarily due to lower US natural gas production. Reduced supply resulted in natural gas storage inventories returning to historically normal levels by the end of 2016.

Comparisons of the prices received in North America Exploration and Production by product type were as follows:

(Quarterly Average)	Dec 31 2016	Sep 30 2016	Dec 31 2015
Wellhead Price ^{(1) (2)}			
Light and medium crude oil and NGLs (\$/bbl)	\$ 45.05	\$ 38.16	\$ 36.45
Pelican Lake heavy crude oil (\$/bbl)	\$ 43.96	\$ 37.57	\$ 33.25
Primary heavy crude oil (\$/bbl)	\$ 43.89	\$ 38.52	\$ 31.14
Bitumen (thermal oil) (\$/bbl)	\$ 39.39	\$ 33.68	\$ 27.92
Natural gas (\$/Mcf)	\$ 2.97	\$ 2.30	\$ 2.73

(1) Amounts expressed on a per unit basis are based on sales volumes.

(2) Net of blending costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices decreased 14% to average \$55.91 per bbl for the year ended December 31, 2016 from \$65.13 per bbl for the year ended December 31, 2015. North Sea realized crude oil prices increased 11% to average \$63.68 per bbl for the fourth quarter of 2016 from \$57.50 per bbl for the fourth quarter of 2015 and increased 6% from \$60.00 per bbl for the third quarter of 2016. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 13% to average \$54.96 per bbl for the year ended December 31, 2016 from \$63.13 per bbl for the year ended December 31, 2015. Offshore Africa realized crude oil prices increased 15% to average \$61.29 per bbl for the fourth quarter of 2016 from \$53.37 per bbl for the fourth quarter of 2015 and increased 5% from \$58.30 per bbl for the third quarter of 2016. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2016 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 5.05	\$ 3.81	\$ 3.71	\$ 3.69	\$ 4.57
North Sea	\$ 0.13	\$ 0.12	\$ 0.14	\$ 0.13	\$ 0.14
Offshore Africa	\$ 2.71	\$ 2.47	\$ 2.61	\$ 2.31	\$ 2.87
Company average	\$ 4.62	\$ 3.48	\$ 3.49	\$ 3.40	\$ 4.30
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 0.17	\$ 0.09	\$ 0.10	\$ 0.08	\$ 0.09
Offshore Africa	\$ 0.29	\$ 0.24	\$ 0.44	\$ 0.28	\$ 0.46
Company average	\$ 0.17	\$ 0.09	\$ 0.10	\$ 0.09	\$ 0.10
Company average (\$/BOE) ⁽¹⁾	\$ 3.16	\$ 2.27	\$ 2.38	\$ 2.21	\$ 2.85

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and natural gas royalties for the three months and year ended December 31, 2016 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 12% of product sales for the year ended December 31, 2016 compared with 13% of product sales for the year ended December 31, 2015. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2016 compared with 13% for the fourth quarter of 2015 and 11% for the third quarter of 2016. The decrease in royalties for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to lower realized crude oil prices during 2016. The increase for the fourth quarter of 2016 from the third quarter of 2016 reflected higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are anticipated to average 13% to 14% of product sales for 2017.

Natural gas royalties averaged approximately 4% of product sales for the year ended December 31, 2016 compared with 4% of product sales for the year ended December 31, 2015. Natural gas royalties averaged approximately 6% of product sales for the fourth quarter of 2016 compared with 4% for the fourth quarter of 2015 and 4% for the third quarter of 2016. The increase in natural gas royalties in the fourth quarter of 2016 from comparable periods primarily reflected higher realized natural gas prices. North America natural gas royalties are anticipated to average 6% to 8% of product sales for 2017.

Offshore Africa

Under the terms of the various Production Sharing Contracts, royalty rates fluctuate based on realized commodity pricing, capital and operating costs, the status of payouts, and the timing of liftings from each field.

Royalty rates as a percentage of product sales averaged approximately 4% for the year ended December 31, 2016, compared with 5% of product sales for the year ended December 31, 2015. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2016, compared with 5% of product sales for the fourth quarter of 2015 and 4% for the third quarter of 2016. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2017.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs (\$/bbl) ⁽¹⁾					
North America	\$ 12.13	\$ 11.69	\$ 11.45	\$ 11.89	\$ 12.51
North Sea	\$ 41.66	\$ 39.41	\$ 56.97	\$ 42.47	\$ 63.67
Offshore Africa	\$ 19.05	\$ 16.32	\$ 26.08	\$ 18.48	\$ 33.32
Company average	\$ 14.28	\$ 13.85	\$ 14.26	\$ 14.10	\$ 15.74
Natural gas (\$/Mcf) ⁽¹⁾					
North America	\$ 1.07	\$ 1.04	\$ 1.17	\$ 1.12	\$ 1.27
North Sea	\$ 3.36	\$ 2.15	\$ 3.27	\$ 3.09	\$ 4.41
Offshore Africa	\$ 2.68	\$ 1.68	\$ 1.55	\$ 1.79	\$ 1.76
Company average	\$ 1.15	\$ 1.08	\$ 1.22	\$ 1.18	\$ 1.34
Company average (\$/BOE) ⁽¹⁾	\$ 11.34	\$ 10.83	\$ 11.55	\$ 11.18	\$ 12.70

(1) Amounts expressed on a per unit basis are based on sales volumes.

North America

North America crude oil and NGLs production expense for the year ended December 31, 2016 decreased 5% to \$11.89 per bbl from \$12.51 per bbl for the year ended December 31, 2015. North America crude oil and NGLs production expense for the fourth quarter of 2016 of \$12.13 per bbl increased 6% from \$11.45 per bbl in the fourth quarter of 2015 and increased 4% from \$11.69 per bbl for the third quarter of 2016. The Company continues to successfully manage its production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. As a result, crude oil and NGLs production expenses for 2016 were near the midpoint of annual guidance of \$11.25 to \$12.25 per bbl. The increase in production costs for the fourth quarter of 2016 from the fourth quarter of 2015 was primarily due to lower sales volumes. The increase from the third quarter of 2016 was primarily due to higher natural gas costs in the Company's thermal areas due to seasonality. North America crude oil and NGLs production expense is anticipated to average \$11.50 to \$13.50 per bbl for 2017.

North America natural gas production expense for the year ended December 31, 2016 decreased 12% to \$1.12 per Mcf from \$1.27 per Mcf for the year ended December 31, 2015. North America natural gas production expense for the fourth quarter of 2016 decreased 9% to \$1.07 per Mcf from \$1.17 per Mcf for the fourth quarter of 2015 and increased 3% from \$1.04 per Mcf for the third quarter of 2016. Consistent with crude oil and NGLs production costs, the Company continues to successfully reduce its natural gas production costs and achieve efficiencies across the asset base, through focused cost and production optimization, together with lower industry service costs. As a result, natural gas production expenses for 2016 were below the midpoint of annual guidance of \$1.05 to \$1.25 per Mcf. The increase in production costs for the fourth quarter of 2016 from the third quarter of 2016 primarily reflected the impact of seasonality. North America natural gas production expense guidance is anticipated to average \$1.00 to \$1.20 per Mcf for 2017.

North Sea

North Sea crude oil production expense for the year ended December 31, 2016 decreased 33% to \$42.47 per bbl from \$63.67 per bbl for the year ended December 31, 2015. North Sea crude oil production expense for the fourth quarter of 2016 decreased 27% to \$41.66 per bbl from \$56.97 per bbl for the fourth quarter of 2015 and increased 6% from \$39.41 per bbl in the third quarter of 2016. The Company continues to successfully reduce its production costs and achieve efficiencies through focused cost and production optimization, together with lower industry service costs. As a result, crude oil and NGLs production expenses for 2016 were below the midpoint of annual guidance of \$40.50 to \$46.50 per bbl. The decrease in production expense in 2016 compared with the prior year also reflected fluctuations in the Canadian dollar and the weakening of the UK pound sterling. The increase in production expense in the fourth quarter of 2016 from the third quarter of 2016 primarily reflected the impact of seasonality. North Sea crude oil production expense guidance is anticipated to average \$33.00 to \$36.00 per bbl for 2017.

Offshore Africa

Offshore Africa oil production expense for the year ended December 31, 2016 decreased 45% to \$18.48 per bbl from \$33.32 per bbl for the year ended December 31, 2015. Offshore Africa crude oil production expense for the fourth quarter of 2016 decreased 27% to average \$19.05 per bbl from \$26.08 per bbl for the fourth quarter of 2015 and increased 17% from \$16.32 per bbl in the third quarter of 2016. The fluctuations in production expense for the three months and year ended December 31, 2016 from the comparable periods were primarily due to the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar. Offshore Africa production expense guidance is anticipated to average \$10.50 to \$12.50 per bbl for 2017.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense	\$ 1,049	\$ 1,031	\$ 1,330	\$ 4,185	\$ 4,909
\$/BOE ⁽¹⁾	\$ 16.71	\$ 16.84	\$ 19.95	\$ 16.79	\$ 18.50

(1) Amounts expressed on a per unit basis are based on sales volumes.

The decrease in depletion, depreciation and amortization expense for the three months and year ended December 31, 2016 from the comparable periods in 2015 was primarily due to lower sales volumes and depletion rates in North America. Depletion, depreciation and amortization expense for the fourth quarter of 2016 increased from the third quarter of 2016 primarily due to additional depletion in the North Sea related to the planned abandonment of the Ninian North platform in 2017.

Depletion, depreciation and amortization on a per barrel basis for the year ended December 31, 2016 decreased 9% to \$16.79 per BOE from \$18.50 per BOE for the year ended December 31, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2016 decreased 16% to \$16.71 per BOE from \$19.95 per BOE for the fourth quarter of 2015 and was comparable with the third quarter of 2016. The decrease in depletion, depreciation and amortization expense per BOE for the three months and year ended December 31, 2016 from comparable periods in 2015 was primarily due to a lower depletable base in North America in 2016 and the derecognition of exploration and evaluation assets in Block CI-514 in Offshore Africa in the fourth quarter of 2015, partially offset by the impact of additional depletion in the North Sea in the fourth quarter of 2016 related to the planned abandonment of the Ninian North platform in 2017.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense	\$ 28	\$ 28	\$ 35	\$ 113	\$ 142
\$/BOE ⁽¹⁾	\$ 0.45	\$ 0.46	\$ 0.54	\$ 0.45	\$ 0.54

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the year ended December 31, 2016 decreased 17% to \$0.45 per BOE from \$0.54 per BOE for the year ended December 31, 2015. Asset retirement obligation accretion expense for the fourth quarter of 2016 decreased 17% to \$0.45 per BOE from \$0.54 per BOE for the fourth quarter of 2015, and was comparable with the third quarter of 2016.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. Horizon achieved record SCO production during the fourth quarter of 2016 averaging 178,063 bbl/d following the completion of the major turnaround and the successful tie-in of Phase 2B during the third quarter. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional Phase 2B capacity and lower industry service costs, cash production costs averaging \$22.53 per bbl were achieved in the fourth quarter.

The Horizon Phase 3 expansion, which is targeted to add 80,000 bbl/d of SCO production is on schedule and targeted for commissioning and startup in the fourth quarter of 2017.

PRODUCT PRICES, ROYALTIES AND TRANSPORTATION – OIL SANDS MINING AND UPGRADING

(\$/bbl) ⁽¹⁾	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
SCO sales price	\$ 64.51	\$ 58.61	\$ 57.49	\$ 58.59	\$ 61.39
Bitumen value for royalty purposes ⁽²⁾	\$ 35.92	\$ 30.16	\$ 24.37	\$ 27.57	\$ 32.14
Bitumen royalties ⁽³⁾	\$ 0.88	\$ 0.62	\$ 0.99	\$ 0.54	\$ 1.08
Transportation	\$ 1.22	\$ 3.40	\$ 1.66	\$ 1.77	\$ 1.81

(1) Amounts expressed on a per unit basis are based on sales volumes excluding turnaround periods.

(2) Calculated as the quarterly and annual average of the bitumen valuation methodology price.

(3) Calculated based on bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged \$58.59 per bbl for the year ended December 31, 2016, a decrease of 5% compared with \$61.39 per bbl for the year ended December 31, 2015. Realized SCO sales prices averaged \$64.51 per bbl for the fourth quarter of 2016, an increase of 12% compared with \$57.49 per bbl for the fourth quarter of 2015 and an increase of 10% compared with \$58.61 per bbl for the third quarter of 2016. The fluctuations in SCO pricing for the three months and year ended December 31, 2016 from comparable periods were primarily due to changes in WTI benchmark pricing and the impact of industry wide planned and unplanned upgrader outages.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Cash production costs	\$ 376	\$ 326	\$ 344	\$ 1,292	\$ 1,332
Less: costs incurred during turnaround periods	—	(151)	—	(151)	(45)
Adjusted cash production costs	\$ 376	\$ 175	\$ 344	\$ 1,141	\$ 1,287
Adjusted cash production costs, excluding natural gas costs	\$ 336	\$ 161	\$ 326	\$ 1,057	\$ 1,212
Adjusted natural gas costs	40	14	18	84	75
Adjusted cash production costs	\$ 376	\$ 175	\$ 344	\$ 1,141	\$ 1,287

(\$/bbl) ⁽¹⁾	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Adjusted cash production costs, excluding natural gas costs	\$ 20.17	\$ 24.92	\$ 27.10	\$ 23.36	\$ 26.95
Natural gas costs	2.36	2.13	1.46	1.84	1.66
Adjusted cash production costs	\$ 22.53	\$ 27.05	\$ 28.56	\$ 25.20	\$ 28.61
Sales (bbl/d)	181,523	70,005	130,990	123,652	123,231

(1) Amounts expressed on a per unit basis are based on sales volumes.

Adjusted cash production costs for the year ended December 31, 2016 decreased 12% to \$25.20 per bbl from \$28.61 per bbl for the year ended December 31, 2015. Adjusted cash production costs for the fourth quarter of 2016 averaged \$22.53 per bbl, a decrease of 21% from \$28.56 per bbl for the fourth quarter of 2015 and a decrease of 17% from \$27.05 per bbl for the third quarter of 2016. The decrease in adjusted cash production costs on a per barrel basis for the three months and year ended December 31, 2016 from comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, additional Phase 2B capacity and lower industry service costs. Cash production costs for 2016, including turnaround costs, were within the Company's previously issued guidance of \$27.00 to \$30.00 per bbl. For 2017, cash production costs are now anticipated to average \$24.00 to \$27.00 per bbl, including turnaround costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Depletion, depreciation and amortization	\$ 198	\$ 182	\$ 139	\$ 662	\$ 562
Less: depreciation incurred during turnaround period	—	(99)	—	(99)	(5)
Adjusted depletion, depreciation and amortization	\$ 198	\$ 83	\$ 139	\$ 563	\$ 557
\$/bbl	\$ 11.84	\$ 12.96	\$ 11.48	\$ 12.43	\$ 12.37

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the year ended December 31, 2016 was comparable with the year ended December 31, 2015. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2016 increased 3% to \$11.84 per bbl from \$11.48 per bbl for the fourth quarter of 2015 and decreased 9% from \$12.96 per bbl for the third quarter of 2016.

Adjusted depletion, depreciation and amortization expense per barrel for the three months and year ended December 31, 2016 fluctuated from comparable periods primarily due to the impact of assets depreciated on a straight line basis and the timing of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense	\$ 7	\$ 8	\$ 8	\$ 29	\$ 31
\$/bbl ⁽¹⁾	\$ 0.44	\$ 1.13	\$ 0.64	\$ 0.64	\$ 0.69

(1) Amounts expressed on a per unit basis are based on sales volumes.

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Asset retirement obligation accretion expense for the year ended December 31, 2016 decreased 7% to \$0.64 per bbl from \$0.69 per bbl for the year ended December 31, 2015. Asset retirement obligation accretion expense of \$0.44 per bbl for the fourth quarter of 2016 decreased 31% from \$0.64 per bbl the fourth quarter of 2015 and decreased 61% from \$1.13 per bbl for the third quarter of 2016, primarily due to fluctuations in sales volumes.

MIDSTREAM

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Revenue	\$ 26	\$ 31	\$ 33	\$ 114	\$ 136
Production expense	5	7	7	25	32
Midstream cash flow	21	24	26	89	104
Depreciation	2	3	3	11	12
Equity loss (gain) on investments	12	4	12	(7)	44
Gain on corporate disposition	(218)	—	—	(218)	—
Segment earnings before taxes	\$ 225	\$ 17	\$ 11	\$ 303	\$ 48

On December 16, 2016, in the Midstream segment, the Company disposed of its interest in the Cold Lake Pipeline, including \$321 million of property, plant and equipment for total net consideration of \$539 million, resulting in a pre-tax gain of \$218 million. Total net consideration was comprised of \$349 million in cash, together with \$190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline with a value of \$29.57 per common share, determined as of the closing date.

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2013, the Company along with APMC, committed each to provide funding up to \$350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2016, the Company and APMC each provided \$99 million of subordinated debt. To date, each party has provided \$324 million of subordinated debt, together with accrued interest thereon of \$61 million for a Company total of \$385 million. Should final Project costs exceed the sanction cost estimate of \$8,500 million, the Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required to reflect an agreed debt to equity ratio and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the second quarter of 2016, Redwater Partnership issued \$500 million of 4.15% series H senior secured bonds due June 2033, \$500 million of 4.35% series I senior secured bonds due January 2039, and \$200 million of senior secured bonds through the reopening of its previously issued 4.75% series G senior secured bonds due June 2037. During the first quarter of 2016, Redwater Partnership issued \$550 million of 4.25% series F senior secured bonds due June 2029, and \$300 million of 4.75% series G senior secured bonds due June 2037.

As at December 31, 2016, Redwater Partnership had additional borrowings of \$1,581 million under its secured \$3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense	\$ 86	\$ 82	\$ 93	\$ 345	\$ 390
\$/BOE ⁽¹⁾	\$ 1.08	\$ 1.21	\$ 1.18	\$ 1.17	\$ 1.26

(1) Amounts expressed on a per unit basis are based on sales volumes.

Administration expense on a per BOE basis for the year ended December 31, 2016 decreased 7% to \$1.17 per BOE from \$1.26 per BOE for the year ended December 31, 2015. Administration expense for the fourth quarter of 2016 of \$1.08 per BOE decreased 8% from \$1.18 per BOE for the fourth quarter of 2015 and decreased 11% from \$1.21 per BOE for the third quarter of 2016. Administration expense per BOE decreased for the year ended December 31, 2016 from the comparable period in 2015 primarily due to lower staffing and general corporate costs.

SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense (Recovery)	\$ 42	\$ 74	\$ 56	\$ 355	\$ (46)

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a \$355 million share-based compensation expense for the year ended December 31, 2016, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. For the year ended December 31, 2016, the Company capitalized \$67 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (December 31, 2015 – \$10 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except per BOE amounts and interest rates)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Expense, gross	\$ 153	\$ 157	\$ 133	\$ 616	\$ 566
Less: capitalized interest	38	67	60	233	244
Expense, net	\$ 115	\$ 90	\$ 73	\$ 383	\$ 322
\$/BOE ⁽¹⁾	\$ 1.43	\$ 1.34	\$ 0.93	\$ 1.30	\$ 1.04
Average effective interest rate	3.8%	3.8%	3.8%	3.9%	3.9%

(1) Amounts expressed on a per unit basis are based on sales volumes.

Gross interest and other financing expense for the three months and year ended December 31, 2016 increased from the comparable periods in 2015 primarily due to the impact of higher average debt levels. Capitalized interest of \$233 million for the year ended December 31, 2016 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense for the year ended December 31, 2016 increased 25% to \$1.30 per BOE from \$1.04 per BOE for the year ended December 31, 2015. Net interest and other financing expense on a per BOE basis for the fourth quarter of 2016 increased 54% to \$1.43 per BOE from \$0.93 per BOE for the fourth quarter of 2015 and increased 7% from \$1.34 per BOE for the third quarter of 2016. The increase for the year ended December 31, 2016 from the comparable period in 2015 was primarily due to higher average debt levels and lower sales volumes.

The increase for the fourth quarter of 2016 from the fourth quarter of 2015 and the third quarter of 2016 was primarily due to lower capitalized interest related to the completion of Horizon Phase 2B. The Company's average effective interest rates for the three months and year ended December 31, 2016 were consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

The Company utilizes various derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These derivative financial instruments are not intended for trading or speculative purposes.

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Crude oil and NGLs financial instruments	\$ —	\$ —	\$ (218)	\$ —	\$ (599)
Foreign currency contracts	(14)	(23)	(37)	8	(244)
Realized (gain) loss	(14)	(23)	(255)	8	(843)
Crude oil and NGLs financial instruments	—	—	189	—	394
Natural gas financial instruments	8	(2)	—	6	—
Foreign currency contracts	(15)	12	(15)	19	(20)
Unrealized (gain) loss	(7)	10	174	25	374
Net (gain) loss	\$ (21)	\$ (13)	\$ (81)	\$ 33	\$ (469)

During the year ended December 31, 2016, net realized risk management losses were related to the settlement of foreign currency contracts. The Company recorded a net unrealized loss of \$25 million (\$21 million after-tax) on its risk management activities for the year ended December 31, 2016, including an unrealized gain of \$7 million (\$7 million after-tax) for the fourth quarter of 2016 (September 30, 2016 - unrealized loss of \$10 million; \$11 million after-tax; December 31, 2015 - unrealized loss of \$174 million; \$128 million after-tax).

Complete details related to outstanding derivative financial instruments at December 31, 2016 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net realized (gain) loss	\$ (2)	\$ 12	\$ (5)	\$ 38	\$ (97)
Net unrealized loss (gain)	162	39	170	(93)	858
Net loss (gain) ⁽¹⁾	\$ 160	\$ 51	\$ 165	\$ (55)	\$ 761

(1) Amounts are reported net of the hedging effect of cross currency swaps.

The net realized foreign exchange loss for the year ended December 31, 2016 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the year ended December 31, 2016 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2016 - unrealized gain of \$67 million, September 30, 2016 - unrealized loss of \$23 million, December 31, 2015 - unrealized gain of \$129 million; year ended December 31, 2016 - unrealized loss of \$295 million, December 31, 2015 - unrealized gain of \$649 million). The US/Canadian dollar exchange rate at December 31, 2016 was US\$0.7448 (September 30, 2016 - US\$0.7624, December 31, 2015 - US\$0.7225).

INCOME TAXES

(\$ millions, except income tax rates)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
North America ⁽¹⁾	\$ (22)	\$ (168)	\$ (66)	\$ (377)	\$ 86
North Sea	—	(43)	(18)	(74)	(117)
Offshore Africa	5	5	5	22	17
PRT recovery – North Sea	(35)	(77)	(71)	(198)	(258)
Other taxes	3	2	2	9	11
Current income tax recovery	(49)	(281)	(148)	(618)	(261)
Deferred corporate income tax (recovery) expense	(55)	(32)	(1)	(106)	216
Deferred PRT expense (recovery) – North Sea	9	50	(32)	(135)	15
Deferred income tax (recovery) expense	(46)	18	(33)	(241)	231
	(95)	(263)	(181)	(859)	(30)
Income tax rate and other legislative changes ⁽²⁾	—	107	—	221	(351)
	\$ (95)	\$ (156)	\$ (181)	\$ (638)	\$ (381)
Effective income tax rate on adjusted net earnings (loss) from operations ⁽³⁾	20%	27%	59%	45%	61%

(1) Includes North America Exploration and Production, Midstream, and Oil Sands Mining and Upgrading segments.

(2) During the third quarter of 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of \$107 million. During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of \$114 million. During the second quarter of 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of \$579 million. During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the PRT, and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's net deferred income tax liability of \$228 million.

(3) Excludes the impact of current and deferred PRT expense and other current income tax expense.

The effective income tax rate for the three months and year ended December 31, 2016 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss). In addition, the effective income tax rate for the three months and year ended December 31, 2016 also reflected the successful resolution of certain prior year tax matters.

The current corporation income tax and PRT recoveries in the North Sea in the three months and year ended December 31, 2016 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

In September 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of \$107 million.

In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these income tax rate changes, the Company's deferred PRT liability was reduced by \$228 million and the deferred corporate income tax liability was increased by \$114 million.

In June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015 resulting in an increase in the Company's deferred corporate income tax liability of \$579 million.

In March 2015, the UK government enacted legislation that reduced the supplementary charge on oil and gas profits from 32% to 20% effective January 1, 2015. In addition, the legislation reduced the PRT rate from 50% to 35% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to prior taxation years for PRT purposes were still recoverable at the previous tax rate of 50%. The legislation also replaced the existing Brownfield Allowance with a new Investment Allowance on qualifying capital expenditures, effective April 1, 2015. The new Investment Allowance is deductible for supplementary charge purposes, subject to certain restrictions. As a result of the new income tax changes, the Company's deferred corporate income tax liability was reduced by \$217 million and the deferred PRT liability was reduced by \$11 million.

The Company files income tax returns in the various jurisdictions in which it operates. These tax returns are subject to periodic examinations in the normal course by the applicable tax authorities. The tax returns as prepared may include filing positions that could be subject to differing interpretations of applicable tax laws and regulations, which may take several years to resolve. The Company does not believe the ultimate resolution of these matters will have a material impact upon the Company's results of operations, financial position or liquidity.

For 2017, the Company expects to recognize current income tax expense of \$100 million to \$150 million in Canada and \$15 million to \$35 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES ⁽¹⁾

(\$ millions)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Exploration and Evaluation					
Net expenditures (proceeds) ^{(2) (3)}	\$ 4	\$ —	\$ (885)	\$ (6)	\$ (805)
Property, Plant and Equipment					
Net property acquisitions ^{(2) (3) (4)}	1	17	(443)	159	(451)
Well drilling, completion and equipping	200	186	237	712	965
Production and related facilities	50	104	154	369	908
Capitalized interest and other ⁽⁵⁾	26	20	26	91	102
Net expenditures	277	327	(26)	1,331	1,524
Total Exploration and Production	281	327	(911)	1,325	719
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	515	400	578	1,920	2,187
Sustaining capital	76	151	55	379	301
Turnaround costs	(3)	103	5	135	18
Capitalized interest and other ⁽⁵⁾	40	77	68	284	224
Total Oil Sands Mining and Upgrading	628	731	706	2,718	2,730
Midstream ⁽⁶⁾	(537)	2	2	(533)	8
Abandonments ⁽⁷⁾	35	122	105	267	370
Head office	4	3	2	17	26
Total net capital expenditures	\$ 411	\$ 1,185	\$ (96)	\$ 3,794	\$ 3,853
By segment					
North America ^{(2) (3) (4)}	\$ 221	\$ 259	\$ (1,126)	\$ 1,048	\$ (119)
North Sea	37	63	34	126	230
Offshore Africa	23	5	181	151	608
Oil Sands Mining and Upgrading	628	731	706	2,718	2,730
Midstream ⁽⁶⁾	(537)	2	2	(533)	8
Abandonments ⁽⁷⁾	35	122	105	267	370
Head office	4	3	2	17	26
Total	\$ 411	\$ 1,185	\$ (96)	\$ 3,794	\$ 3,853

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values and other fair value adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Includes Business Combinations.

(3) Includes proceeds from the Company's disposition of properties.

(4) The above noted figures in the fourth quarter of 2015 include non-cash share consideration of \$985 million received from PrairieSky on the disposition of royalty income assets and the impact of other pre-tax gains on the sale of other properties totaling \$49 million recognized in 2015.

(5) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.

(6) The above noted figures in the fourth quarter of 2016 include non-cash share consideration of \$190 million received from Inter Pipeline on the disposition of Midstream assets.

(7) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.

The Company's strategy is focused on building a diversified asset base that is balanced among various products. In order to facilitate efficient operations, the Company concentrates its activities in core areas. The Company focuses on maintaining its land inventories to enable the continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs.

Net capital expenditures for the year ended December 31, 2016 were \$3,794 million compared with \$3,853 million for the year ended December 31, 2015. Net capital expenditures for the fourth quarter of 2016 were \$411 million compared with net proceeds of \$96 million for the fourth quarter of 2015 and net expenditures of \$1,185 million for the third quarter of 2016.

Net capital expenditures for the three months and year ended December 31, 2016 included the disposition of the Company's ownership interest in the Cold Lake Pipeline in the Midstream segment. Total net consideration on the disposition was comprised of \$349 million in cash, together with \$190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") with a value of \$29.57 per common share, determined as of the closing date.

On December 15, 2016 the Company announced its 2017 Capital Budget. The 2017 budget reflects a continued focus on proactive capital allocation and lowering overall operating and capital cost structures, and is targeted at \$3,890 million.

Drilling Activity

(number of wells)	Three Months Ended			Year Ended	
	Dec 31 2016	Sep 30 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net successful natural gas wells	4	—	4	9	19
Net successful crude oil wells ⁽¹⁾	81	85	2	174	115
Dry wells	3	4	—	7	6
Stratigraphic test / service wells	62	6	73	268	166
Total	150	95	79	458	306
Success rate (excluding stratigraphic test / service wells)	97%	96%	100%	96%	96%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 20% of the total net capital expenditures for the year ended December 31, 2016 compared with approximately 1% for the year ended December 31, 2015.

During the fourth quarter of 2016, the Company targeted 4 net natural gas wells, including 3 wells in Northeast British Columbia and 1 well in Northwest Alberta. The Company also targeted 83 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 69 primary heavy crude oil wells, 2 Pelican Lake heavy crude oil wells and 8 bitumen (thermal oil) wells were drilled. Another 4 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the fourth quarter of 2016 averaged approximately 129,300 bbl/d compared with approximately 135,100 bbl/d for the fourth quarter of 2015 and approximately 103,500 bbl/d for the third quarter of 2016. Production volumes in the fourth quarter of 2016 reflected the cyclic nature of thermal oil production at Primrose and were within guidance.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 47,500 bbl/d in the fourth quarter of 2016 compared with 49,300 bbl/d in the fourth quarter of 2015 and 47,600 bbl/d in the third quarter of 2016.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2016 focused on the commissioning of the hydrogen unit, hydrotreater unit, vacuum distillation and diluent recovery unit, sour water concentrator, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot. Phase 3 work also continued with engineering, procurement and construction related to tailings retrofit, combined hydrotreater and sulphur recovery units.

During the turnaround in the third quarter, the Company successfully completed the tie-in of major components as planned. The construction, commissioning and operational teams at Horizon worked together to execute a safe and effective start-up of the Phase 2B expansion. The Horizon Phase 3 expansion, which is targeted to add 80,000 bbl/d of SCO production is on schedule and targeted for commissioning and startup in the fourth quarter of 2017.

North Sea

During the fourth quarter of 2016, the Company drilled 1 gross well (0.9 net well) at Ninian.

Due to the Company's continued focus on proactive capital allocation and lowering overall operating and capital cost structures, the Company plans to commence abandonment of the Ninian North platform in 2017. Abandonment activities at Ninian North have been reflected in 2017 guidance.

Offshore Africa

During the second quarter of 2016, the Company demobilized the drilling rigs at Baobab and Espoir. No additional drilling activity occurred for the remainder of 2016.

LIQUIDITY AND CAPITAL RESOURCES

(\$ millions, except ratios)	Three Months Ended		
	Dec 31 2016	Sep 30 2016	Dec 31 2015
Working capital ⁽¹⁾	\$ 1,056	\$ 489	\$ 1,193
Long-term debt ^{(2) (3)}	\$ 16,805	\$ 17,292	\$ 16,794
Share capital	\$ 4,671	\$ 4,367	\$ 4,541
Retained earnings	21,526	21,237	22,765
Accumulated other comprehensive income	70	40	75
Shareholders' equity	\$ 26,267	\$ 25,644	\$ 27,381
Debt to book capitalization ^{(3) (4)}	39%	40%	38%
Debt to market capitalization ^{(3) (5)}	26%	27%	34%
After-tax return on average common shareholders' equity ⁽⁶⁾	(1%)	(2%)	(2%)
After-tax return on average capital employed ^{(3) (7)}	0%	(1%)	(1%)

(1) Calculated as current assets less current liabilities, excluding the current portion of long-term debt.

(2) Includes the current portion of long-term debt.

(3) Long-term debt is stated at its carrying value, net of fair value adjustments, original issue discounts and premiums and transaction costs.

(4) Calculated as current and long-term debt; divided by the book value of common shareholders' equity plus current and long-term debt.

(5) Calculated as current and long-term debt; divided by the market value of common shareholders' equity plus current and long-term debt.

(6) Calculated as net earnings (loss) for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings (loss) plus after-tax interest and other financing expense for the twelve month trailing period; as a percentage of average capital employed for the period.

At December 31, 2016, the Company's capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2015. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

On an ongoing basis the Company continues to focus on its balance sheet strength and available liquidity by:

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
 - During the third quarter of 2016, the Company issued \$1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has \$2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
 - In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
 - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US \$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program.
 - During the first quarter of 2016, the Company prepaid \$250 million of the previously outstanding \$1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2016, the \$750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new \$125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

During the third quarter of 2016, the Company repaid US\$250 million of 6.00% notes.

During the first quarter of 2016, the Company repaid US\$500 million of three-month LIBOR plus 0.375% notes.

At December 31, 2016, the Company had in place bank credit facilities of \$7,350 million, of which approximately \$3,043 million, net of commercial paper issuances of \$336 million, was available for general corporate purposes.

At December 31, 2016, the Company had total US dollar denominated debt with a carrying amount of \$10,612 million (US\$7,905 million), excluding transaction costs. This included \$4,437 million (US\$3,305 million) hedged by way of cross currency swaps (US\$2,150 million) and foreign currency forwards (US\$1,155 million). The fixed repayment amount of these hedging instruments is \$3,975 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately \$462 million to \$10,150 million as at December 31, 2016.

Long-term debt was \$16,805 million at December 31, 2016, resulting in a debt to book capitalization ratio of 39% (December 31, 2015 – 38%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when funds flow from operations is greater than current

investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2016 are discussed in note 7 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At December 31, 2016, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for January 2017 to October 2017. Subsequent to year end, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for February 2017 to December 2017 and 17,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for March 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at December 31, 2016 are discussed in note 14 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2016, there were 1,110,952,000 common shares outstanding (December 31, 2015 – 1,094,668,000 common shares) and 58,299,000 stock options outstanding. As at February 28, 2017, the Company had 1,112,581,000 common shares outstanding and 55,957,000 stock options outstanding.

On March 1, 2017, the Board of Directors approved an increase in the quarterly dividend to \$0.275 per common share, beginning with the dividend payable on April 1, 2017. On November 2, 2016, the Board of Directors approved an increase in the quarterly dividend to \$0.25 per common share (previous quarterly dividend rate of \$0.23 per common share), beginning with the dividend payable on January 1, 2017. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

During the second quarter of 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of \$546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

On March 1, 2017 the Board of Directors approved the Company's application for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,814,309 common shares, over a 12 month period commencing upon receipt of applicable regulatory and other approvals.

COMMITMENTS AND OFF BALANCE SHEET ARRANGEMENTS

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2016:

(\$ millions)	2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	\$ 441	\$ 404	\$ 306	\$ 300	\$ 258	\$ 2,337
Offshore equipment operating leases and offshore drilling	\$ 166	\$ 105	\$ 59	\$ 34	\$ 33	\$ 9
Long-term debt ^{(1) (2)}	\$ 1,813	\$ 2,841	\$ 2,705	\$ 1,768	\$ 671	\$ 7,072
Interest and other financing expense ⁽³⁾	\$ 626	\$ 539	\$ 475	\$ 434	\$ 395	\$ 4,126
Office leases	\$ 44	\$ 43	\$ 43	\$ 43	\$ 40	\$ 154
Other	\$ 53	\$ 2	\$ 2	\$ 2	\$ 2	\$ 35

(1) Long-term debt represents principal repayments only and does not reflect original issue discounts and premiums or transaction costs.

(2) Included in the 2017 long-term debt repayment commitments, the Company had US\$1,100 million of 5.70% debt securities due May 2017, hedged by way of a cross currency swap with a principal repayment amount fixed at \$1,287 million.

(3) Interest and other financing expense amounts represent the scheduled fixed rate and variable rate cash interest payments related to long-term debt. Interest on variable rate long-term debt was estimated based upon prevailing interest rates and foreign exchange rates as at December 31, 2016.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of Horizon Phase 3. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2015 and the unaudited interim financial statements for the year ended December 31, 2016.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2015.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Dec 31 2016	Dec 31 2015
ASSETS			
Current assets			
Cash and cash equivalents		\$ 17	\$ 69
Accounts receivable		1,434	1,277
Current income taxes		851	677
Inventory		689	525
Prepays and other		149	162
Investments	5	913	974
Current portion of other long-term assets	6	283	375
		4,336	4,059
Exploration and evaluation assets	3	2,382	2,586
Property, plant and equipment	4	50,910	51,475
Other long-term assets	6	1,020	1,155
		\$ 58,648	\$ 59,275
LIABILITIES			
Current liabilities			
Accounts payable		\$ 595	\$ 571
Accrued liabilities		2,222	2,089
Current portion of long-term debt	7	1,812	1,729
Current portion of other long-term liabilities	8	463	206
		5,092	4,595
Long-term debt	7	14,993	15,065
Other long-term liabilities	8	3,223	2,890
Deferred income taxes		9,073	9,344
		32,381	31,894
SHAREHOLDERS' EQUITY			
Share capital	10	4,671	4,541
Retained earnings		21,526	22,765
Accumulated other comprehensive income	11	70	75
		26,267	27,381
		\$ 58,648	\$ 59,275

Commitments and contingencies (note 15).

Approved by the Board of Directors on March 1, 2017.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended		Year Ended	
		Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Product sales		\$ 3,672	\$ 2,963	\$ 11,098	\$ 13,167
Less: royalties		(214)	(170)	(575)	(804)
Revenue		3,458	2,793	10,523	12,363
Expenses					
Production		1,092	1,119	4,099	4,726
Transportation and blending		558	575	2,003	2,379
Depletion, depreciation and amortization	3, 4	1,249	1,472	4,858	5,483
Administration		86	93	345	390
Share-based compensation	8	42	56	355	(46)
Asset retirement obligation accretion	8	35	43	142	173
Interest and other financing expense		115	73	383	322
Risk management activities	14	(21)	(81)	33	(469)
Foreign exchange loss (gain)		160	165	(55)	761
Gain on disposition of properties and corporate acquisitions and dispositions	3, 4	(218)	(690)	(250)	(739)
(Gain) loss from investments	5, 6	(111)	18	(327)	50
		2,987	2,843	11,586	13,030
Earnings (loss) before taxes		471	(50)	(1,063)	(667)
Current income tax recovery	9	(49)	(148)	(618)	(261)
Deferred income tax (recovery) expense	9	(46)	(33)	(241)	231
Net earnings (loss)		\$ 566	\$ 131	\$ (204)	\$ (637)
Net earnings (loss) per common share					
Basic	13	\$ 0.51	\$ 0.12	\$ (0.19)	\$ (0.58)
Diluted	13	\$ 0.51	\$ 0.12	\$ (0.19)	\$ (0.58)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net earnings (loss)	\$ 566	\$ 131	\$ (204)	\$ (637)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized loss during the period, net of taxes of \$2 million (2015 – \$1 million) – three months ended; \$3 million (2015 – \$2 million) – year ended	(14)	(15)	(18)	(23)
Reclassification to net earnings (loss), net of taxes of \$2 million (2015 – \$1 million) – three months ended; \$2 million (2015 – \$2 million) – year ended	(10)	(2)	(13)	(13)
	(24)	(17)	(31)	(36)
Foreign currency translation adjustment				
Translation of net investment	54	25	26	60
Other comprehensive income (loss), net of taxes	30	8	(5)	24
Comprehensive income (loss)	\$ 596	\$ 139	\$ (209)	\$ (613)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended	
		Dec 31 2016	Dec 31 2015
Share capital	10		
Balance – beginning of year		\$ 4,541	\$ 4,432
Issued upon exercise of stock options		559	91
Previously recognized liability on stock options exercised for common shares		117	18
Return of capital on PrairieSky Royalty Ltd. share distribution	5	(546)	—
Balance – end of year		4,671	4,541
Retained earnings			
Balance – beginning of year		22,765	24,408
Net earnings (loss)		(204)	(637)
Dividends on common shares	10	(1,035)	(1,006)
Balance – end of year		21,526	22,765
Accumulated other comprehensive income	11		
Balance – beginning of year		75	51
Other comprehensive income (loss), net of taxes		(5)	24
Balance – end of year		70	75
Shareholders' equity		\$ 26,267	\$ 27,381

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended		Year Ended	
		Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Operating activities					
Net earnings (loss)		\$ 566	\$ 131	\$ (204)	\$ (637)
Non-cash items					
Depletion, depreciation and amortization		1,249	1,472	4,858	5,483
Share-based compensation		42	56	355	(46)
Asset retirement obligation accretion		35	43	142	173
Unrealized risk management (gain) loss		(7)	174	25	374
Unrealized foreign exchange loss (gain)		162	170	(93)	858
(Gain) loss from investments	5, 6	(106)	23	(299)	55
Deferred income tax (recovery) expense		(46)	(33)	(241)	231
Gain on disposition of properties and corporate acquisitions and dispositions		(218)	(690)	(250)	(739)
Current income tax on disposition of properties		—	33	—	33
Other		(70)	(103)	(32)	(22)
Abandonment expenditures		(35)	(105)	(267)	(370)
Net change in non-cash working capital		(317)	314	(542)	239
		1,255	1,485	3,452	5,632
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		(706)	(73)	342	970
Issue of medium-term notes, net	7	—	—	998	107
Repayment of US dollar debt securities	7	—	—	(834)	—
Issue of common shares on exercise of stock options		238	7	559	91
Dividends on common shares		(254)	(503)	(758)	(1,251)
Net change in non-cash working capital		—	—	—	(40)
		(722)	(569)	307	(123)
Investing activities					
Net (expenditures) proceeds on exploration and evaluation assets ⁽¹⁾		(4)	316	6	236
Net expenditures on property, plant and equipment ⁽¹⁾⁽²⁾		(642)	(1,100)	(3,803)	(4,704)
Current income tax on disposition of properties		—	(33)	—	(33)
Investment in other long-term assets		—	—	(99)	(112)
Net change in non-cash working capital		111	(60)	85	(852)
		(535)	(877)	(3,811)	(5,465)
(Decrease) increase in cash and cash equivalents		(2)	39	(52)	44
Cash and cash equivalents – beginning of period		19	30	69	25
Cash and cash equivalents – end of period		\$ 17	\$ 69	\$ 17	\$ 69
Interest paid, net		\$ 118	\$ 94	\$ 617	\$ 541
Income taxes (received) paid		\$ (4)	\$ (94)	\$ (444)	\$ 42

(1) Net proceeds on exploration and evaluation assets and net expenditures on property, plant and equipment in the fourth quarter of 2015 exclude non-cash share consideration of \$985 million received from PrairieSky Royalty Ltd. ("PrairieSky") on the disposition of royalty income assets.

(2) Net expenditures on property, plant and equipment in the fourth quarter of 2016 exclude non-cash share consideration of \$190 million received from Inter Pipeline Ltd. ("Inter Pipeline") on the disposition of the Company's interest in the Cold Lake Pipeline.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars, unless otherwise stated, unaudited)

1. ACCOUNTING POLICIES

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire, Gabon, and South Africa in Offshore Africa.

The Horizon Oil Sands Mining and Upgrading segment ("Horizon") produces synthetic crude oil through bitumen mining and upgrading operations.

Within Western Canada, the Company maintains certain midstream activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("Redwater Partnership"), a general partnership formed in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34, "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2015, except as discussed in Note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2015.

2. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2016, the Company adopted the amendment to IFRS 11 "Joint Arrangements" to clarify the accounting treatment when an entity acquires interests in joint ventures and joint operations. The amendment requires these acquisitions to be accounted for as business combinations. The Company adopted this amendment prospectively. Adoption of this amended standard did not result in an impact to the Company's consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2015	\$ 2,500	\$ —	\$ 86	\$ —	2,586
Additions	20	—	9	—	29
Transfers to property, plant and equipment	(211)	—	—	—	(211)
Disposals/derecognitions	(3)	—	(18)	—	(21)
Foreign exchange adjustments	—	—	(1)	—	(1)
At December 31, 2016	\$ 2,306	\$ —	\$ 76	\$ —	2,382

During the year ended December 31, 2016, the Company disposed of a number of North America exploration and evaluation assets totalling \$3 million for consideration of \$35 million, resulting in a pre-tax gain on sale of properties of \$32 million.

In connection with the Company's notice of withdrawal from Block CI-12 in Côte d'Ivoire, Offshore Africa in the second quarter of 2016, the Company derecognized \$18 million of exploration and evaluation assets.

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2015	\$ 60,540	\$ 7,414	\$ 5,173	\$ 24,343	\$ 577	\$ 378	\$ 98,425
Additions	1,462	186	116	2,822	6	17	4,609
Transfers from E&E assets	211	—	—	—	—	—	211
Disposals/derecognitions	(566)	—	—	(127)	(349)	—	(1,042)
Foreign exchange adjustments and other	—	(220)	(157)	—	—	—	(377)
At December 31, 2016	\$ 61,647	\$ 7,380	\$ 5,132	\$ 27,038	\$ 234	\$ 395	\$ 101,826
Accumulated depletion and depreciation							
At December 31, 2015	\$ 35,347	\$ 5,264	\$ 3,659	\$ 2,294	\$ 132	\$ 254	\$ 46,950
Expense	3,440	457	243	662	11	27	4,840
Disposals/derecognitions	(486)	—	—	(127)	(28)	—	(641)
Foreign exchange adjustments and other	10	(137)	(105)	(1)	—	—	(233)
At December 31, 2016	\$ 38,311	\$ 5,584	\$ 3,797	\$ 2,828	\$ 115	\$ 281	\$ 50,916
Net book value							
- at December 31, 2016	\$ 23,336	\$ 1,796	\$ 1,335	\$ 24,210	\$ 119	\$ 114	\$ 50,910
- at December 31, 2015	\$ 25,193	\$ 2,150	\$ 1,514	\$ 22,049	\$ 445	\$ 124	\$ 51,475

Project costs not subject to depletion and depreciation	Dec 31 2016	Dec 31 2015
Horizon	\$ —	\$ 6,017
Kirby Thermal Oil Sands – North	\$ 846	\$ 816

During the year ended December 31, 2016, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of \$159 million. These transactions were accounted for using the acquisition method of accounting. In connection with these acquisitions, the Company assumed associated asset retirement obligations of \$30 million. No net deferred income tax liabilities or pre-tax gains were recognized on these acquisitions.

On December 16, 2016, in the Midstream segment, the Company disposed of its interest in the Cold Lake Pipeline, comprising \$321 million of property, plant and equipment for total net consideration of \$539 million, resulting in a pre-tax gain of \$218 million. Total net consideration was comprised of \$349 million in cash, together with \$190 million of non-cash share consideration of approximately 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") with a value of \$29.57 per common share, determined as of the closing date.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the year ended December 31, 2016, pre-tax interest of \$233 million (December 31, 2015 – \$244 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (December 31, 2015 – 3.9%).

5. INVESTMENTS

As at December 31, 2016, the Company had the following investments:

	Dec 31 2016	Dec 31 2015
Investment in PrairieSky Royalty Ltd.	\$ 723	\$ 974
Investment in Inter Pipeline Ltd.	190	—
	\$ 913	\$ 974

Investment in PrairieSky Royalty Ltd.

In connection with the disposal of a number of North America royalty income assets in 2015, the Company acquired approximately 44.4 million common shares of PrairieSky Royalty Ltd. ("PrairieSky").

During the second quarter of 2016, the Company completed the net distribution of approximately 21.8 million PrairieSky common shares to the shareholders of record of the Company as at June 3, 2016, completing the previously announced Plan of Arrangement. The distribution was recognized as a return of capital of \$546 million. Subsequent to the distribution, the Company's ownership interest in PrairieSky was less than 10% of the issued and outstanding common shares of PrairieSky.

The Company's remaining investment of approximately 22.6 million common shares does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2016, the Company's investment in PrairieSky was classified as a current asset.

The (gain) loss from the investment in PrairieSky was comprised as follows:

	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Fair value (gain) loss from PrairieSky	\$ (118)	\$ 11	\$ (292)	\$ 11
Dividend income from PrairieSky	(4)	(5)	(27)	(5)
	\$ (122)	\$ 6	\$ (319)	\$ 6

Investment in Inter Pipeline Ltd.

On December 16, 2016, as partial consideration for the disposal of the Company's interest in the Cold Lake Pipeline, the Company received non-cash share consideration of \$190 million, comprised of approximately 6.4 million common shares of Inter Pipeline at \$29.57 per common share determined as of the closing date (refer to Note 4). Inter Pipeline is in the business of petroleum transportation, natural gas liquids processing, and bulk liquid storage in western Canada and Europe.

The Company's investment does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2016, the Company's investment in Inter Pipeline was classified as a current asset.

The gain from the investment in Inter Pipeline was comprised as follows:

	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Fair value gain from Inter Pipeline	\$ —	\$ —	\$ —	\$ —
Dividend income from Inter Pipeline	(1)	—	(1)	—
	\$ (1)	\$ —	\$ (1)	\$ —

6. OTHER LONG-TERM ASSETS

	Dec 31 2016	Dec 31 2015
Investment in North West Redwater Partnership	\$ 261	\$ 254
North West Redwater Partnership subordinated debt ⁽¹⁾	385	254
Risk Management (note 14)	489	854
Other	168	168
	1,303	1,530
Less: current portion	283	375
	\$ 1,020	\$ 1,155

(1) Includes accrued interest.

Investment in North West Redwater Partnership

The Company's 50% interest in Redwater Partnership is accounted for using the equity method based on Redwater Partnership's voting and decision-making structure and legal form. Redwater Partnership has entered into agreements to construct and operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2013, the Company along with APMC, committed each to provide funding up to \$350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2016, the Company and APMC each provided \$99 million of subordinated debt. To date, each party has provided \$324 million of subordinated debt, together with accrued interest thereon of \$61 million for a Company total of \$385 million. Should final Project costs exceed the sanction cost estimate of \$8,500 million, the Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required to reflect an agreed debt to equity ratio and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion.

During the second quarter of 2016, Redwater Partnership issued \$500 million of 4.15% series H senior secured bonds due June 2033, \$500 million of 4.35% series I senior secured bonds due January 2039, and \$200 million of senior secured bonds through the reopening of its previously issued 4.75% series G senior secured bonds due June 2037. During the first quarter of 2016, Redwater Partnership issued \$550 million of 4.25% series F senior secured bonds due June 2029, and \$300 million of 4.75% series G senior secured bonds due June 2037.

As at December 31, 2016, Redwater Partnership had additional borrowings of \$1,581 million under its secured \$3,500 million syndicated credit facility.

Under its processing agreement, beginning on the earlier of the commercial operations date of the refinery and June 1, 2018, the Company is unconditionally obligated to pay its 25% pro rata share of the debt portion of the monthly cost of service toll, including interest, fees and principal repayments, of the syndicated credit facility and bonds, over the tolling period of 30 years.

During the three months ended December 31, 2016, the Company recognized an equity loss from Redwater Partnership of \$12 million (three months ended December 31, 2015 – loss of \$12 million; year ended December 31, 2016 – gain of \$7 million; year ended ended December 31, 2015 – loss of \$44 million).

Redwater Partnership has entered into various agreements related to the engineering, procurement and construction of the Project. These contracts can be cancelled by Redwater Partnership upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

7. LONG-TERM DEBT

	Dec 31 2016	Dec 31 2015
Canadian dollar denominated debt, unsecured		
Bank credit facilities	\$ 2,758	\$ 2,385
Medium-term notes	3,500	2,500
	6,258	4,885
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2016 - US\$905 million; December 31, 2015 - US\$657 million)	1,213	909
Commercial paper (December 31, 2016 - US\$250 million; December 31, 2015 - US\$500 million)	336	692
US dollar debt securities (December 31, 2016 - US\$6,750 million; December 31, 2015 - US\$7,500 million)	9,063	10,380
	10,612	11,981
Long-term debt before transaction costs and original issue discounts, net	16,870	16,866
Less: original issue discounts, net ⁽¹⁾	(10)	(10)
transaction costs ⁽¹⁾⁽²⁾	(55)	(62)
	16,805	16,794
Less: current portion of commercial paper	336	692
current portion of other long-term debt ⁽¹⁾⁽²⁾	1,476	1,037
	\$ 14,993	\$ 15,065

(1) The Company has included unamortized original issue discounts and premiums, and directly attributable transaction costs in the carrying amount of the outstanding debt.

(2) Transaction costs primarily represent underwriting commissions charged as a percentage of the related debt offerings, as well as legal, rating agency and other professional fees.

Bank Credit Facilities and Commercial Paper

As at December 31, 2016, the Company had in place bank credit facilities of \$7,350 million available for general corporate purposes, comprised of:

- a \$100 million demand credit facility;
- a \$1,500 million non-revolving term credit facility maturing April 2018;
- a \$750 million non-revolving term credit facility maturing February 2019;
- a \$125 million non-revolving term credit facility maturing February 2019;
- a \$2,425 million revolving syndicated credit facility maturing June 2019;
- a \$2,425 million revolving syndicated credit facility maturing June 2020; and
- a £15 million demand credit facility related to the Company's North Sea operations.

Each of the \$2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.

During the first quarter of 2016, the Company prepaid \$250 million of the previously outstanding \$1,000 million non-revolving term credit facility and extended the maturity date to February 2019 from January 2017. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2016, the \$750 million facility was fully drawn. During the first quarter of 2016, the Company also entered into a new \$125 million non-revolving term credit facility maturing February 2019, which was fully drawn at December 31, 2016. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.

Borrowings under the \$1,500 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at December 31, 2016, the \$1,500 million facility was fully drawn.

The Company's borrowings under its US commercial paper program are authorized up to a maximum US\$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2016 was 1.9% (December 31, 2015 – 1.7%), and on total long-term debt outstanding for the year ended December 31, 2016 was 3.9% (December 31, 2015 – 3.9%).

At December 31, 2016, letters of credit and guarantees aggregating \$219 million, including a \$39 million financial guarantee related to Horizon and \$82 million of letters of credit related to North Sea operations, were outstanding. The letters of credit are supported by dedicated credit facilities.

Medium-Term Notes

During the third quarter of 2016, the Company issued \$1,000 million of 3.31% medium-term notes due February 2022. After issuing these securities, the Company has \$2,000 million remaining on its base shelf prospectus that allows for the offer for sale from time to time of up to \$3,000 million of medium-term notes in Canada, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

During the third quarter of 2016, the Company repaid US\$250 million of 6.00% notes.

During the first quarter of 2016, the Company repaid US\$500 million of three-month LIBOR plus 0.375% notes.

In October 2015, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US\$3,000 million of debt securities in the United States, which expires in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

8. OTHER LONG-TERM LIABILITIES

	Dec 31 2016	Dec 31 2015
Asset retirement obligations	\$ 3,243	\$ 2,950
Share-based compensation	426	128
Other	17	18
	3,686	3,096
Less: current portion	463	206
	\$ 3,223	\$ 2,890

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 5.2% (December 31, 2015 – 5.9%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2016	Dec 31 2015
Balance – beginning of year	\$ 2,950	\$ 4,221
Liabilities incurred	3	7
Liabilities acquired, net	30	129
Liabilities settled	(267)	(370)
Asset retirement obligation accretion	142	173
Revision of cost, inflation rates and timing estimates	(68)	(313)
Change in discount rate	493	(1,150)
Foreign exchange adjustments	(40)	253
Balance – end of year	3,243	2,950
Less: current portion	95	101
	\$ 3,148	\$ 2,849

Share-Based Compensation

As the Company's Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered, a liability for potential cash settlements is recognized. The current portion represents the maximum amount of the liability payable within the next twelve month period if all vested stock options are surrendered for cash settlement.

	Dec 31 2016	Dec 31 2015
Balance – beginning of year	\$ 128	\$ 203
Share-based compensation expense (recovery)	355	(46)
Cash payment for stock options surrendered	(7)	(1)
Transferred to common shares	(117)	(18)
Capitalized to (recovered from) Oil Sands Mining and Upgrading	67	(10)
Balance – end of year	426	128
Less: current portion	368	105
	\$ 58	\$ 23

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Current corporate income tax (recovery) expense – North America	\$ (22)	\$ (66)	\$ (377)	\$ 86
Current corporate income tax recovery – North Sea	—	(18)	(74)	(117)
Current corporate income tax expense – Offshore Africa	5	5	22	17
Current PRT ⁽¹⁾ recovery – North Sea	(35)	(71)	(198)	(258)
Other taxes	3	2	9	11
Current income tax recovery	(49)	(148)	(618)	(261)
Deferred corporate income tax (recovery) expense	(55)	(1)	(106)	216
Deferred PRT ⁽¹⁾ expense (recovery) – North Sea	9	(32)	(135)	15
Deferred income tax (recovery) expense	(46)	(33)	(241)	231
Income tax recovery	\$ (95)	\$ (181)	\$ (859)	\$ (30)

(1) Petroleum Revenue Tax.

In September 2016, the UK government enacted legislation to reduce the supplementary charge on oil and gas profits from 20% to 10% effective January 1, 2016, resulting in a decrease in the Company's deferred corporate income tax liability of \$107 million.

In March 2016, the UK government enacted legislation to reduce the PRT rate from 35% to 0% effective January 1, 2016. Allowable abandonment expenditures eligible for carryback to 2015 and prior taxation years for PRT purposes are still recoverable at a PRT rate of 50%. As a result of these income tax changes, the Company's deferred PRT liability was reduced by \$228 million and the deferred corporate income tax liability was increased by \$114 million.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Year Ended Dec 31, 2016	
	Number of shares (thousands)	Amount
Balance – beginning of year	1,094,668	\$ 4,541
Issued upon exercise of stock options	16,284	559
Previously recognized liability on stock options exercised for common shares	—	117
Return of capital on PrairieSky Royalty Ltd. share distribution (note 5)	—	(546)
Balance – end of year	1,110,952	\$ 4,671

Dividend Policy

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 1, 2017, the Board of Directors set the regular quarterly dividend at \$0.275 per common share, an increase from the previous quarterly dividend of \$0.25 per common share, which was announced on November 2, 2016.

Normal Course Issuer Bid

On March 1, 2017, the Board of Directors approved the Company's application for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,814,309 common shares, over a 12 month period commencing upon receipt of applicable regulatory and other approvals.

Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2016:

	Year Ended Dec 31, 2016	
	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	74,615	\$ 34.88
Granted	11,002	\$ 34.97
Surrendered for cash settlement	(817)	\$ 34.47
Exercised for common shares	(16,284)	\$ 34.31
Forfeited	(10,217)	\$ 39.66
Outstanding – end of year	58,299	\$ 34.22
Exercisable – end of year	20,747	\$ 33.75

The Option Plan is a "rolling 9%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 9% of the common shares outstanding from time to time.

11. ACCUMULATED OTHER COMPREHENSIVE INCOME

The components of accumulated other comprehensive income, net of taxes, were as follows:

	Dec 31 2016	Dec 31 2015
Derivative financial instruments designated as cash flow hedges	\$ 27	\$ 58
Foreign currency translation adjustment	43	17
	\$ 70	\$ 75

12. CAPITAL DISCLOSURES

The Company does not have any externally imposed regulatory capital requirements for managing capital. The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of current and long-term debt divided by the sum of the carrying value of shareholders' equity plus current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2016, the ratio was within the target range at 39%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Dec 31 2016	Dec 31 2015
Long-term debt ⁽¹⁾	\$ 16,805	\$ 16,794
Total shareholders' equity	\$ 26,267	\$ 27,381
Debt to book capitalization	39%	38%

(1) Includes the current portion of long-term debt.

13. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Weighted average common shares outstanding – basic (thousands of shares)	1,107,181	1,094,528	1,100,471	1,093,862
Effect of dilutive stock options (thousands of shares)	11,187	299	—	—
Weighted average common shares outstanding – diluted (thousands of shares)	1,118,368	1,094,827	1,100,471	1,093,862
Net earnings (loss)	\$ 566	\$ 131	\$ (204)	\$ (637)
Net earnings (loss) per common share – basic	\$ 0.51	\$ 0.12	\$ (0.19)	\$ (0.58)
– diluted	\$ 0.51	\$ 0.12	\$ (0.19)	\$ (0.58)

14. FINANCIAL INSTRUMENTS

The carrying amounts of the Company's financial instruments by category were as follows:

Asset (liability)	Dec 31, 2016				
	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	\$ 1,434	\$ —	\$ —	\$ —	\$ 1,434
Investments	—	913	—	—	913
Other long-term assets	385	4	485	—	874
Accounts payable	—	—	—	(595)	(595)
Accrued liabilities	—	—	—	(2,222)	(2,222)
Long-term debt ⁽¹⁾	—	—	—	(16,805)	(16,805)
	\$ 1,819	\$ 917	\$ 485	\$ (19,622)	\$ (16,401)

Asset (liability)	Dec 31, 2015				
	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	\$ 1,277	\$ —	\$ —	\$ —	\$ 1,277
Investments	—	974	—	—	974
Other long-term assets	254	36	818	—	1,108
Accounts payable	—	—	—	(571)	(571)
Accrued liabilities	—	—	—	(2,089)	(2,089)
Long-term debt ⁽¹⁾	—	—	—	(16,794)	(16,794)
	\$ 1,531	\$ 1,010	\$ 818	\$ (19,454)	\$ (16,095)

(1) Includes the current portion of long-term debt.

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The fair values of the Company's recurring other long-term assets and fixed rate long-term debt are outlined below:

Asset (liability) ^{(1) (2)}	Dec 31, 2016				
	Carrying amount		Fair value		
			Level 1	Level 2	Level 3
Investments ⁽³⁾	\$ 913	\$ 913	\$ —	\$ —	\$ —
Other long-term assets ⁽⁴⁾	\$ 874	\$ —	\$ 489	\$ —	\$ 385
Fixed rate long-term debt ^{(5) (6)}	\$ (12,498)	\$ (13,217)	\$ —	\$ —	\$ —

Dec 31, 2015

Asset (liability) ⁽¹⁾⁽²⁾	Carrying amount		Fair value			
			Level 1	Level 2	Level 3	
Investments ⁽³⁾	\$	974	\$	974	\$	—
Other long-term assets ⁽⁴⁾	\$	1,108	\$	—	\$	854
Fixed rate long-term debt ⁽⁵⁾⁽⁶⁾	\$	(12,808)	\$	(12,431)	\$	—

(1) Excludes financial assets and liabilities where the carrying amount approximates fair value due to the liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities).

(2) There were no transfers between Level 1, 2 and 3 financial instruments.

(3) The fair value of the investments are based on quoted market prices.

(4) The fair value of North West Redwater Partnership subordinated debt is based on the present value of future cash receipts.

(5) The fair value of fixed rate long-term debt has been determined based on quoted market prices.

(6) Includes the current portion of fixed rate long-term debt.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

Asset (liability)	Dec 31 2016	Dec 31 2015
Derivatives held for trading		
Foreign currency forward contracts	\$	10
Natural gas AECO swaps		(6)
Cash flow hedges		
Foreign currency forward contracts		16
Cross currency swaps		469
	\$	489
		\$
		854
Included within:		
Current portion of other long-term assets	\$	222
Other long-term assets		267
	\$	489
		\$
		854

For the year ended December 31, 2016, the Company recognized a gain of \$7 million (year ended December 31, 2015 – gain of \$5 million) related to ineffectiveness arising from cash flow hedges.

The estimated fair value of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications. Level 2 fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows and discount rates. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs as applicable, including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

Risk Management

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The changes in estimated fair values of derivative financial instruments included in the risk management asset were recognized in the financial statements as follows:

Asset (liability)	Dec 31 2016	Dec 31 2015
Balance – beginning of year	\$ 854	\$ 599
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	(25)	(374)
Foreign exchange	(304)	669
Other comprehensive loss	(36)	(40)
Balance – end of year	489	854
Less: current portion	222	305
	\$ 267	\$ 549

Net (gains) losses from risk management activities were as follows:

	Three Months Ended		Year Ended	
	Dec 31 2016	Dec 31 2015	Dec 31 2016	Dec 31 2015
Net realized risk management (gain) loss	\$ (14)	\$ (255)	\$ 8	\$ (843)
Net unrealized risk management (gain) loss	(7)	174	25	374
	\$ (21)	\$ (81)	\$ 33	\$ (469)

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases. At December 31, 2016, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

Sales contracts ⁽¹⁾

	Remaining term	Volume	Weighted average price	Index
Natural Gas				
AECO swaps	Jan 2017 - Oct 2017	50,000 GJ/d	\$2.80	AECO

(1) Subsequent to December 31, 2016, the Company entered into 50,000 bbl/d of US\$50.00 - US\$60.10 WTI collars for the period February to December 2017, and 17,500 bbl/d of US\$50.00 - US\$60.03 WTI collars for the period March to December 2017.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2016, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into cross currency swap contracts and foreign currency forward contracts to manage known currency exposure on US dollar denominated long-term debt, commercial paper and working capital. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. At December 31, 2016, the Company had the following cross currency swap contracts outstanding:

	Remaining term	Amount	Exchange rate (US\$/C\$)	Interest rate (US\$)	Interest rate (C\$)
Cross currency					
Swaps	Jan 2017 — May 2017	US\$1,100	1.170	5.70%	5.10%
	Jan 2017 — Nov 2021	US\$500	1.022	3.45%	3.96%
	Jan 2017 — Mar 2038	US\$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2016 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2016, the Company had US\$1,928 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US\$1,155 million designated as cash flow hedges.

b) Credit Risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At December 31, 2016, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2016, the Company had net risk management assets of \$489 million with specific counterparties related to derivative financial instruments (December 31, 2015 – \$854 million).

The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates for financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	\$ 595	\$ —	\$ —	\$ —
Accrued liabilities	\$ 2,222	\$ —	\$ —	\$ —
Long-term debt ⁽¹⁾	\$ 1,813	\$ 2,841	\$ 5,144	\$ 7,072

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

15. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	\$ 441	\$ 404	\$ 306	\$ 300	\$ 258	\$ 2,337
Offshore equipment operating leases and offshore drilling	\$ 166	\$ 105	\$ 59	\$ 34	\$ 33	\$ 9
Office leases	\$ 44	\$ 43	\$ 43	\$ 43	\$ 40	\$ 154
Other	\$ 53	\$ 2	\$ 2	\$ 2	\$ 2	\$ 35

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of subsequent phases of Horizon. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

16. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
Segmented product sales	2,241	1,970	7,209	9,222	168	133	570	638	163	148	603	482	2,572	2,251	8,382	10,342
Less: royalties	(192)	(151)	(524)	(732)	—	—	(1)	(1)	(8)	(7)	(26)	(22)	(200)	(158)	(551)	(755)
Segmented revenue	2,049	1,819	6,685	8,490	168	133	569	637	155	141	577	460	2,372	2,093	7,831	9,587
Segmented expenses																
Production	556	592	2,186	2,603	104	110	403	544	53	67	200	223	713	769	2,789	3,370
Transportation and blending	546	554	1,941	2,309	11	18	48	61	—	1	2	2	557	573	1,991	2,372
Depletion, depreciation and amortization	859	1,065	3,465	4,248	143	107	458	388	47	158	262	273	1,049	1,330	4,185	4,909
Asset retirement obligation accretion	16	23	66	93	9	10	35	39	3	2	12	10	28	35	113	142
Realized risk management activities	(14)	(255)	8	(843)	—	—	—	—	—	—	—	—	(14)	(255)	8	(843)
Gain on disposition of properties and corporate acquisitions and dispositions	—	(690)	(32)	(739)	—	—	—	—	—	—	—	—	—	(690)	(32)	(739)
(Gain)/loss from investments	(123)	6	(320)	6	—	—	—	—	—	—	—	—	(123)	6	(320)	6
Total segmented expenses	1,840	1,295	7,314	7,677	267	245	944	1,032	103	228	476	508	2,210	1,768	8,734	9,217
Segmented earnings (loss) before the following	209	524	(629)	813	(99)	(112)	(375)	(395)	52	(87)	101	(48)	162	325	(903)	370
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss (gain)																
Total non-segmented expenses																
Earnings (loss) before taxes																
Current income tax recovery																
Deferred income tax (recovery) expense																
Net earnings (loss)																

Total

**Inter-segment
elimination and other**

Midstream

Oil Sands Mining and Upgrading

	Three Months Ended		Year Ended		Three Months Ended		Year Ended		Three Months Ended		Year Ended	
	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
(millions of Canadian dollars, unaudited)												
Segmented product sales	1,079	693	2,657	2,764	26	33	114	136	(5)	(14)	3,672	2,963
Less: royalties	(14)	(12)	(24)	(49)	—	—	—	—	—	—	(214)	(170)
Segmented revenue	1,065	681	2,633	2,715	26	33	114	136	(5)	(14)	3,458	2,793
Segmented expenses												
Production	376	344	1,292	1,332	5	7	25	32	(2)	(1)	1,092	1,119
Transportation and blending	20	20	80	82	—	—	—	—	(19)	(18)	558	575
Depletion, depreciation and amortization	198	139	662	562	2	3	11	12	—	—	1,249	1,472
Asset retirement obligation accretion	7	8	29	31	—	—	—	—	—	—	35	43
Realized risk management activities	—	—	—	—	—	—	—	—	—	—	(14)	(255)
Gain on disposition of properties and corporate acquisitions and dispositions	—	—	—	—	(218)	—	(218)	—	—	—	(218)	(690)
(Gain) loss from investments	—	—	—	—	12	12	(7)	44	—	—	(111)	18
Total segmented expenses	601	511	2,063	2,007	(199)	22	(189)	88	(21)	(19)	2,591	2,282
Segmented earnings (loss) before the following	464	170	570	708	225	11	303	48	16	5	867	511
Non-segmented expenses												
Administration											86	93
Share-based compensation											42	56
Interest and other financing expense											115	73
Unrealized risk management activities											(7)	174
Foreign exchange loss (gain)											160	165
Total non-segmented expenses											396	561
Earnings (loss) before taxes											471	(50)
Current income tax recovery											(49)	(148)
Deferred income tax (recovery) expense											(46)	(33)
Net earnings (loss)											566	131
											(204)	(637)
											10,533	11,229
											(10)	1,134
											345	390
											355	(46)
											383	322
											25	374
											(55)	761
											1,053	1,801
											(1,063)	(667)
											(618)	(261)
											(241)	231
											(204)	(637)

Capital Expenditures ⁽¹⁾

	Year Ended					
	Dec 31, 2016			Dec 31, 2015		
	Net expenditures (proceeds)	Non-cash and fair value changes ⁽²⁾	Capitalized costs	Net expenditures (proceeds)	Non-cash and fair value changes ⁽²⁾	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America ⁽³⁾	\$ 17	\$ (211)	\$ (194)	\$ (260)	\$ (666)	\$ (926)
North Sea	—	—	—	—	—	—
Offshore Africa	9	(18)	(9)	35	(96)	(61)
	\$ 26	\$ (229)	\$ (203)	\$ (225)	\$ (762)	\$ (987)
Property, plant and equipment						
Exploration and Production						
North America	\$ 1,143	\$ (36)	\$ 1,107	\$ 1,171	\$ (1,237)	\$ (66)
North Sea	126	60	186	230	(217)	13
Offshore Africa	142	(26)	116	573	(49)	524
	1,411	(2)	1,409	1,974	(1,503)	471
Oil Sands Mining and Upgrading ⁽⁴⁾	2,718	(23)	2,695	2,730	(335)	2,395
Midstream ⁽⁵⁾	(315)	(28)	(343)	8	(1)	7
Head office	17	—	17	26	—	26
	\$ 3,831	\$ (53)	\$ 3,778	\$ 4,738	\$ (1,839)	\$ 2,899

(1) This table provides a reconciliation of capitalized costs including derecognitions and does not include the impact of foreign exchange adjustments.

(2) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, transfers of property, plant and equipment to inventory due to change in use, and other fair value adjustments.

(3) The above noted figures for 2016 do not include the impact of a pre-tax cash gain of \$32 million on the disposition of exploration and evaluation assets.

(4) Net expenditures for Oil Sands Mining and Upgrading also include capitalized interest and share-based compensation.

(5) The above noted figures in 2016 do not include a pre-tax cash and non-cash gain of \$218 million on the disposition of certain Midstream assets to Inter Pipeline.

Segmented Assets

	Dec 31 2016	Dec 31 2015
Exploration and Production		
North America	\$ 28,892	\$ 30,937
North Sea	2,269	2,734
Offshore Africa	1,580	1,755
Other	29	73
Oil Sands Mining and Upgrading	24,852	22,598
Midstream	912	1,054
Head office	114	124
	\$ 58,648	\$ 59,275

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated October 2015. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2016:

Interest coverage (times)	
Net earnings (loss) ⁽¹⁾	(0.6)x
Funds flow from operations ⁽²⁾	6.9x

(1) *Net earnings (loss) plus income taxes and interest expense excluding current and deferred PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.*

(2) *Funds flow from operations plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.*

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Corporate Information

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Stock Listing

Toronto Stock Exchange

Trading Symbol - CNQ

New York Stock Exchange

Trading Symbol - CNQ

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