Canadian Natural

PRESS RELEASE

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CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2015 FOURTH QUARTER AND YEAR END RESULTS AND 2016 BUDGET CALGARY, ALBERTA – MARCH 3, 2016 – FOR IMMEDIATE RELEASE

Commenting on the fourth quarter 2015 results, Steve Laut, President of Canadian Natural stated, “2015 was a strong operational year for Canadian Natural despite the significant drop in commodity prices. In 2015, we were able to reduce original budgeted capital spending by $3.4 billion, but still delivered 8% production growth. At the same time, we significantly lowered the cost structure within all our operations, and delivered excellent reserve replacement ratios of 179% on proved developed producing reserves and 165% on total proved reserves, and exceptional finding, development and acquisition costs.

2016 is a milestone year for Canadian Natural with the start-up of Horizon Phase 2B just 7 months away. The Company’s transition to a long life, low decline asset base continues. Upon such start-up, even at US$30/bbl WTI, our cash flow in the fourth quarter of 2016 when annualized will cover, on a go forward basis, all forecast base annual capital expenditures and current annualized dividends, as Horizon expansion capital spending drops dramatically with the start of Horizon Phase 2B.

In 2017, Horizon expansion capital will drop to approximately one billion dollars and the 80,000 bbl/d of Horizon Phase 3 is targeted to start in the fourth quarter of 2017, generating significant additional unallocated cash flow. In 2018, Horizon expansion capital drops to zero with targeted production in excess of 250,000 bbl/d for the entire year. Combined with lower operating costs, the Horizon project will generate substantial cash flow, which along with the 2017 unallocated cash flow will allow the balance sheet to quickly strengthen.”

Canadian Natural’s Chief Financial Officer, Corey Bieber, continued, “Canadian Natural effectively managed our balance sheet in 2015 through proactive capital spending cuts, lowering our overall operating and capital cost structure and the monetization of a significant portion of our third party royalty stream. In 2016, we are proactively managing capital spending to the current price environment and will maintain additional capital flexibility we can exercise if we choose. Horizon Phase 2B start up is 7 months away, at which time the nature of the Company’s production profile takes another step towards a long life, low decline profile. Canadian Natural currently has in place sufficient liquidity to ensure the funding of all targeted activities in 2016 and 2017. By the fourth quarter of 2016, annualized cash flow will then be in a position to cover all base annual capital and current annualized dividend requirements. As a result, Canadian Natural has maintained its investment grade ratings and believes our current dividend policy is appropriate reflecting the strength and robustness of the Company’s operations and assets.”

QUARTERLY HIGHLIGHTS

($ Millions, except per common share amounts)	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Net earnings (loss)	**$ 131**	$ (111)	$ 1,198	**$ (637)**	$ 3,929
Per common share – basic	**$ 0.12**	$ (0.10)	$ 1.10	**$ (0.58)**	$ 3.60
– diluted	**$ 0.12**	$ (0.10)	$ 1.09	**$ (0.58)**	$ 3.58
Adjusted net earnings from operations (1)	**$ (49)**	$ 113	$ 756	**$ 263**	$ 3,811
Per common share – basic	**$ (0.04)**	$ 0.10	$ 0.69	**$ 0.24**	$ 3.49
– diluted	**$ (0.04)**	$ 0.10	$ 0.69	**$ 0.24**	$ 3.47
Cash flow from operations (2)	**$ 1,379**	$ 1,533	$ 2,368	**$ 5,785**	$ 9,587
Per common share – basic	**$ 1.26**	$ 1.40	$ 2.17	**$ 5.29**	$ 8.78
– diluted	**$ 1.26**	$ 1.40	$ 2.16	**$ 5.28**	$ 8.74
Capital expenditures, net of dispositions	**$ (96)**	$ 1,240	$ 2,220	**$ 3,853**	$ 11,744
Daily production, before royalties					
Natural gas (MMcf/d)	**1,703**	1,653	1,733	**1,726**	1,555
Crude oil and NGLs (bbl/d)	**572,000**	573,135	572,040	**564,188**	531,194
Equivalent production (BOE/d) (3)	**855,800**	848,701	860,920	**851,901**	790,410

(1) Adjusted net 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) 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

- Canadian Natural demonstrated strong operational performance throughout 2015 despite significantly reducing its 2015 drilling programs for both crude oil and natural gas, as a result of sharply lower commodity pricing during the year. The Company's 2015 drilling programs consisted of 306 net wells, an 80% decrease from its 2014 drilling programs of 1,554 net wells. Through a focused drilling program, strategic acquisitions and productivity enhancements, the Company was able to achieve record annual production volumes in 2015 of 851,901 BOE/d, representing an increase of 8% from 2014 levels.
  - Record annual crude oil and NGL production volumes in 2015 averaged 564,188 bbl/d, representing an increase of 6% from 2014 levels, and within the Company's 2015 annual guidance range of 555,000 bbl/d to 591,000 bbl/d.
    - Horizon Oil Sands ("Horizon"), Canadian Natural's world class oil sands mining and upgrading operations, achieved record annual production of 122,911 bbl/d of synthetic crude oil ("SCO") in 2015, representing an 11% increase from 2014 levels. Through its safe, steady and reliable operations and a strong focus on continuous improvement, the Company's annual operating costs averaged C$28.61/bbl (US$22.37/bbl equivalent) in 2015, a 23% reduction from 2014 levels.

    - Thermal in situ oil sands ("thermal in situ") annual production volumes reached record levels of 129,835 bbl/d, representing a 20% increase from 2014 volumes. During the year, the Kirby South steam assisted gravity drainage ("SAGD") volumes advanced toward facility capacity as annual production volumes averaged 29,467 bbl/d with November 2015 volumes exceeding 41,000 bbl/d. The Company continues to enhance its focus on effective and efficient operations at its thermal in situ projects achieving annual operating costs of $10.43/bbl, a 17% reduction from 2014 levels.
    - Pelican Lake annual production improved by 1% to 50,818 bbl/d from 2014 levels and achieved strong annual operating costs of $7.24/bbl, a 15% reduction from 2014. This leading edge polymer flood continues to perform with increasing production volumes and decreasing operating costs despite no drilling activity in the project since Q3/14. Canadian Natural leverages innovation and technology to create value through strong netbacks and robust economic returns.
    - North America light crude oil and NGL annual production averaged a record level of 91,283 bbl/d in 2015, an increase of 2% from 2014 volumes. The increase in volumes result from strategic acquisitions offset by expected production declines. In 2015, 4 net wells were drilled compared to 101 net wells drilled in 2014. 2015 operating costs were reduced by 14% over 2014 levels.
    - International Exploration & Production ("E&P") annual production volumes increased to 41,295 bbl/d, representing a 39% increase from 2014 levels. North Sea improved volumes by 28% to 22,216 bbl/d while Offshore Africa's infill drilling programs at Espoir and Baobab increased production by 54% to 19,079 bbl/d. 2015 International operating costs decreased by 19% from 2014 levels.
  - The Company achieved record annual natural gas volumes of 1,726 MMcf/d, an increase of 11% from 2014 levels primarily as a result of opportunistic acquisitions and a focused liquids-rich natural gas drilling program. 2015 operating costs were reduced by 9% from 2014 levels.

- During 2015, Canadian Natural continued to advance its Horizon expansion project, the major component of its transition to a longer life, low decline asset base. At December 31, 2015, physical progress of Horizon Phase 2B and 3 were 79% and 74% complete, respectively. Total Horizon expansion project capital costs continue to trend below budget estimate.
- The start-up of Horizon Phase 2B is targeted in 7 months and will add 45,000 bbl/d of production capacity. Project capital in 2016 is targeted to be approximately $2 billion, the majority of which will be spent over the first nine months of 2016. In 2017, Horizon project capital costs are targeted to decline to approximately $1 billion for Phase 3 completion, which will add incremental production volumes of 80,000 bbl/d. At expansion completion, targeted for Q4/17, Canadian Natural targets total Horizon production volumes to average 250,000 bbl/d of SCO with operating costs trending below C$25.00/bbl (less than US$18.00/bbl equivalent).
- The Company initially announced its original 2015 capital budget in November 2014 at $8.6 billion. As a result of steeply declining commodity prices, the Company responded quickly and revised the budget in January 2015 to $6.2 billion. Due to the significant capital flexibility within the Company's program, three subsequent instances of cost cutting measures were implemented during the rest of 2015, ultimately reducing the gross capital program by approximately $3.4 billion to approximately $5.2 billion. As a result of an effective acquisitions and dispositions program in 2015, the largest transaction being the royalty land disposition to PrairieSky, the Company's 2015 net expenditure program ended up totaling approximately $3.9 billion.
- Despite the significant reduction in the Company's 2015 original capital budget by $3.4 billion, 2015 total corporate production volumes increased to 851,901 BOE/d, representing an increase of 8% over 2014 levels.

- In 2015, Canadian Natural continued to focus on effective and efficient operations reducing operating and capital costs throughout its business. As a result, the Company achieved over $1.1 billion in operating cost savings year-over-year based on 2014 unit rates versus 2015 unit rates, which is demonstrated by the product comparison in the table below.

Operating Costs (Canadian $)		**2015**		2014	**Year-over-Year Percent Reduction**
North America Light Crude Oil and NGLs ($/bbl)	**$**	**14.88**	$	17.24	**14%**
Pelican Lake Heavy Crude Oil ($/bbl)	**$**	**7.24**	$	8.52	**15%**
Primary Heavy Crude Oil ($/bbl)	**$**	**15.01**	$	17.61	**15%**
Thermal Oil Sands In Situ ($/bbl)	**$**	**10.43**	$	12.61	**17%**
Horizon Oil Sands Mining and Upgrading ($/bbl) (1)	**$**	**28.61**	$	37.18	**23%**
North Sea Light Crude Oil ($/bbl)	**$**	**63.67**	$	74.04	**14%**
Offshore Africa Light Crude Oil ($/bbl)	**$**	**33.32**	$	43.97	**24%**
North America Natural Gas ($/Mcf)	**$**	**1.27**	$	1.42	**11%**
Total Overall ($/BOE)	**$**	**15.18**	$	18.29	**17%**

(1) Horizon operating costs adjusted to reflect the impact of maintenance turnarounds.

- From 2014 to 2015, Canadian Natural attained drilling, completions, and facility cost reductions of a capital nature from 20% to 25% throughout its North America E&P operations. These reductions contributed to the Company's ability to decrease its 2015 capital expenditure program by approximately $3.4 billion since November 2014. For 2016, the Company targets to achieve additional drilling and completions cost reductions from 5% to 10% and from 10% to 20% in facility cost reductions.
- In December 2015, Canadian Natural completed the sale of a substantial portion of its royalty assets to PrairieSky for an aggregate price of $1.66 billion, consisting of $673 million in cash and the issuance of approximately 44.4 million PrairieSky common shares valued at $22.16 per common share.
  - From its royalty assets, the Company divested a portion of its production volumes and added to its royalty portfolio through certain opportunistic acquisitions executed through 2015. The Company's estimate of current production volumes attributed to its royalty portfolio is approximately 2,100 BOE/d, of which 1,100 BOE/d are Canadian Natural royalty volumes.
  - Canadian Natural has agreed with PrairieSky to distribute, by no later than December 31, 2016, by way of a dividend, return of capital or otherwise (subject to regulatory approval and securities and tax regulations) sufficient PrairieSky Common Shares so that Canadian Natural, after such distribution, owns, directly or indirectly, less than 10% of the issued and outstanding shares of PrairieSky (the "Share Distribution"). Canadian Natural's current intention is to distribute to its shareholders the majority of the Share Consideration on or after its next Annual and Special Meeting of Shareholders in May 2016, providing Canadian Natural shareholders with the opportunity to participate directly and indirectly in the combined royalty business of PrairieSky. Prior to the Share Distribution, Canadian Natural has agreed not to sell or otherwise dispose, or agree to sell or otherwise dispose, of the PrairieSky Common Shares comprising the Share Consideration, subject to certain exceptions.
- Canadian Natural realized cash flow from operations in 2015 of approximately $5.8 billion. The decrease in 2015 from 2014 primarily reflects lower benchmark pricing partially offset by reduced operating costs and increased natural gas and crude oil sales volumes.
- For 2015, the Company had a net loss of $637 million compared to net earnings of $3.9 billion in 2014. Adjusted net earnings from operations were $263 million in 2015 compared to $3.8 billion in 2014. Changes in adjusted net earnings primarily reflect the changes in cash flow from operations.

- Canadian Natural maintains significant financial stability and liquidity represented in part by committed bank credit facilities. As at December 31, 2015, the Company had in place bank credit facilities of $7,481 million, of which $3,495 million was available.
  - During the first two quarters of 2015, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018 and extended its two existing revolving syndicated term credit facilities to mature in June 2019 and June 2020. The result of the extension of the two revolving $2,425 million facilities netted an additional $350 million of liquidity. The Company's credit facilities provide that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 65%.
  - Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings from the $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. In addition the Company entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Canadian Natural maintained a strong balance sheet with debt to book capitalization of 38% at December 31, 2015.
- Subsequent to December 31, 2015, Standard & Poor's Rating Services maintained the Company's investment grade unsecured long-term and short-term credit ratings and DBRS Limited maintained the Company's investment grade unsecured long-term credit rating. Additionally, Moody's Investors Service, Inc. adjusted the Company's credit ratings within the investment grade debt rating scale.
- Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on April 1, 2016. On an annualized basis, the dividend of C$0.92 per share remains unchanged from the previous annual dividend rate and reflects the Board of Director's confidence in the Company's cash flow.
- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs as at December 31, 2015 (all reserve values are Company Gross unless stated otherwise).
  - Proved crude oil, SCO, bitumen and NGL reserves increased 4% to 4.70 billion barrels. Proved natural gas reserves increased 2% to 6.11 Tcf. Total proved reserves increased 4% to 5.71 billion BOE.
  - Proved developed producing reserve additions and revisions, including acquisitions and dispositions, were 468 million barrels of crude oil, SCO, bitumen and NGL and 527 billion cubic feet of natural gas. The total proved developed producing reserves replacement ratio was 179%.
  - Proved reserve additions and revisions, including acquisitions and dispositions, were 390 million barrels of crude oil, SCO, bitumen and NGL and 735 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio was 165%. The total proved BOE reserve life index is 21.5 years.
  - Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 1% to 7.62 billion barrels. Proved plus probable natural gas reserves increased 5% to 8.51 Tcf. Total proved plus probable reserves increased 2% to 9.04 billion BOE.
  - Proved plus probable reserve additions and revisions, including acquisitions and dispositions, were 294 million barrels of crude oil, bitumen, SCO and NGL and 1.0 trillion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 148%. The total proved plus probable BOE reserve life index is 34.0 years.
  - Corporate finding, development and acquisition (FD&A) costs, excluding changes in future development capital (FDC) and excluding proceeds from the royalty asset disposition, were strong at $9.96/BOE on a proved basis and $11.08/BOE on a proved plus probable basis.
  - Corporate FD&A costs including changes in future development capital cannot be calculated since the decrease in FDC exceeds 2015 capital expenditures. However, North America FD&A costs including FDC, excluding Horizon, were $1.69/BOE on a proved basis and $0.27/BOE on a proved plus probable basis.
  - The corporate net present values, at a 10% discount rate, of the future net revenue, before income taxes, was $65.2 billion on a proved basis which is a 5% decrease from the year end 2014 evaluation. On a proved plus probable basis, the net present value was $89.0 billion, a 5% decrease from year end 2014.

Fourth Quarter Overview

- Canadian Natural continued to demonstrate solid operational performance during the fourth quarter of 2015. Total crude oil and NGL production was 572,000 bbl/d for Q4/15, which was comparable to Q4/14 and Q3/15 levels. Highlights of the Company's quarterly operational performance include:
  - Horizon quarterly production volumes averaged 129,050 bbl/d of SCO, 1% higher than Q4/14 levels and 2% lower than Q3/15 levels. Excellent operating costs of $28.56/bbl (US$21.39/bbl equivalent) were achieved at Horizon in Q4/15, a 17% decrease from Q4/14 levels.
  - Thermal in situ quarterly production volumes were 135,135 bbl/d and Kirby South production increased to 33,746 bbl/d with November 2015 volumes at Kirby South exceeding 41,000 bbl/d. Q4/15 thermal in situ volumes increased by 14% and 1% from Q4/14 and Q3/15 levels respectively.
  - International E&P Q4/15 production volumes improved to 47,942 bbl/d, an increase of 41% and 10% from Q4/14 and Q3/15 volumes respectively. North Sea volumes were 5% and 3% higher than Q4/14 and Q3/15 levels respectively, while Offshore Africa production improved 106% and 18% from Q4/14 and Q3/15 levels respectively.
- Total natural gas production was 1,703 MMcf/d in Q4/15, a decrease of 2% from Q4/14 levels and an increase of 3% from Q3/15 levels. The decrease in production levels from the same quarter in the previous year reflect third party transmission pipeline restrictions in Northwest Alberta, as well as shut-ins of production volumes due to low natural gas pricing, which was largely driven by pipeline restrictions and partially offset by an increase in International quarterly natural gas production volumes.
- During the fourth quarter, the Company continued to realize operating cost reductions. Operating costs achieved in Q4/15 were lower than 2015 average annual operating costs illustrating the Company's ability to maintain its focus on enhancing the effectiveness and efficiency of its operating cost structures.

Operating Costs (Canadian $)	**2015**	**Q4/15**
North America Light Crude Oil and NGLs ($/bbl)	$ 14.88	$ 13.55
Pelican Lake Heavy Crude Oil ($/bbl)	$ 7.24	$ 6.75
Primary Heavy Crude Oil ($/bbl)	$ 15.01	$ 13.90
Thermal Oil Sands In Situ ($/bbl)	$ 10.43	$ 9.59
Horizon Oil Sands Mining and Upgrading ($/bbl) (1)	$ 28.61	$ 28.56
North Sea Light Crude Oil ($/bbl)	$ 63.67	$ 56.97
Offshore Africa Light Crude Oil ($/bbl)	$ 33.32	$ 26.08
North America Natural Gas ($/Mcf)	$ 1.27	$ 1.17

(1) Horizon operating costs adjusted to reflect the impact of maintenance turnarounds.

- Capital expenditures, compared to budget, decreased by another $193 million in Q4/15 reflecting the Company's ability to attain further drilling and completions cost reductions and further facility cost decreases throughout its North America E&P operations.
- Canadian Natural generated cash flow from operations of approximately $1.4 billion in Q4/15 compared to approximately $2.4 billion in Q4/14 and $1.5 billion in Q3/15. The decrease in Q4/15 from Q4/14 primarily reflects lower benchmark pricing volumes partially offset by reduced operating costs.
- Net earnings from operations for Q4/15 were $131 million, compared to net earnings of $1,198 million in Q4/14 and a net loss of $111 million in Q3/15. In Q4/15, adjusted net loss from operations was $49 million, compared to adjusted net earnings of $756 million in Q4/14 and $113 million in Q3/15. Changes in adjusted net earnings primarily reflect the changes in cash flow.

HIGHLIGHTS OF THE 2016 BUDGET

- Canadian Natural develops its capital budgets to be flexible and nimble allowing the Company to proactively adapt to changing market conditions. Commensurate to this, the Company continues to progress its transition to a longer life, low decline asset base and maintain the strength of its balance sheet. For 2016, Canadian Natural targets its capital program to range from $3.5 billion to $3.9 billion, with overall 2016 production volumes targeted to be 2% less than 2015 annual production volumes, at the midpoint of guidance. The majority of the Company's expenditure program, approximately $2 billion, is allocated to advancing the completion of Phases 2B and 3 of the Horizon expansion project.
- Overall production in 2016 is targeted to be between 809,000 BOE/d and 868,000 BOE/d, with a product mix of approximately 64% crude oil and NGLs and 36% natural gas.
- Overall crude oil and NGLs production for 2016 is targeted to range from 514,000 bbl/d to 563,000 bbl/d.
- Canadian Natural's total natural gas production for 2016 is targeted to range from 1,770 MMcf/d to 1,830 MMcf/d.
- For 2016, the Company is committed to further enhancing its effective and efficient operations and is targeting to deliver further operating cost reductions in North America natural gas of approximately 6% and in its crude oil and NGL operating areas of approximately 8%, based on unit rates compared to 2015 levels.
- As reflected by the Company's 2016 capital budget, Canadian Natural is committed to advancing the completion of the Horizon expansion project, the major component of its transition to longer life, low decline asset base. The start-up of Horizon Phase 2B is targeted in 7 months and will add 45,000 bbl/d of production capacity. Project capital in 2016 is targeted to be approximately $2 billion, the majority of which will be spent over the first nine months of 2016. In 2017, Horizon project capital costs are targeted to decline in 2017 to approximately $1 billion for Phase 3 completion, which will add incremental production volumes of 80,000 bbl/d. At expansion completion, targeted for Q4/17, Canadian Natural targets total Horizon production volumes to average 250,000 bbl/d of SCO with operating costs trending below C$25.00/bbl (less than US$18.00/bbl equivalent).
- Due to Canadian Natural's large, high quality, and diversified asset base, the Company is able to achieve a strong overall 2016 corporate base production decline rate of approximately 15%, which assumes no development activity.
- Details of Canadian Natural's Q1/16 production guidance and 2016 annual production and capital guidance can be found on the Company's website at http://www.cnrl.com/investor-information/corporate-guidance-and-hedging.html

CORPORATE UPDATE

Douglas A. Proll, Executive Vice-President, announced his decision to retire from Canadian Natural effective February 1, 2016. Doug joined Canadian Natural in 2001 as Vice-President, Finance. He was appointed Chief Financial Officer and Senior Vice-President, Finance in May 2005. In March 2013, he assumed an Executive Vice-President role. During his tenure at Canadian Natural, Doug made a significant contribution to the growth of the Company. Canadian Natural and the Board would like to thank Doug for his dedicated service and loyalty throughout the years.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

In order to facilitate effective and efficient operations, Canadian Natural focuses its activities in core regions where the Company owns a substantial land base and associated infrastructure. Land inventories are maintained to enable continuous exploitation of play types and geological trends, greatly reducing overall exploration risk. By owning and operating associated infrastructure, the Company is able to maximize utilization of its production facilities, thereby increasing control over production costs. Furthermore, the Company maintains large project inventories and production diversification among each of the commodities it produces; 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. A large diversified project portfolio enables the effective allocation of capital to higher return opportunities.

Drilling Activity

(number of wells)	2015 Gross	2015 Net	2014 Gross	2014 Net
	Year Ended Dec 31			
Crude oil	**133**	**115**	1,112	1,023
Natural gas	**32**	**19**	100	75
Dry	**6**	**6**	21	19
Subtotal	**171**	**140**	1,233	1,117
Stratigraphic test / service wells	**206**	**166**	444	437
Total	**377**	**306**	1,677	1,554
Success rate (excluding stratigraphic test / service wells)		**96%**		98%

- As a direct result of the decrease in crude oil and natural gas pricing and other external events, the Company proactively reduced its 2015 drilling programs. Drilling activity, excluding strat/service wells, in Q4/15 consisted of 6 net wells compared to 349 net wells in Q4/14. The Company's 2015 annual drilling program, excluding strat/service wells, consisted of 140 net wells, an 87% decrease from its 2014 drilling program of 1,117 net wells.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs production (bbl/d)	**259,873**	264,709	291,002	**270,147**	283,012
Net wells targeting crude oil	**1**	67	332	**112**	1,021
Net successful wells drilled	**1**	63	324	**106**	1,003
Success rate	**100%**	94%	98%	**95%**	98%

- Annual production volumes of North America crude oil and NGLs averaged 270,147 bbl/d in 2015, a decrease of 5% from 2014 levels. The year over year production decline reflects an 89% reduction in drilling activity from 1,021 net wells in 2014 to 112 net wells in 2015.
- Record North America light crude oil and NGL annual production averaged 91,283 bbl/d in 2015, an increase of 2% from 2014 volumes. The increase in volumes result from strategic acquisitions offset by expected production declines. In 2015, 4 net wells were drilled compared to 101 net wells drilled in 2014. Operating costs were reduced by 14% from 2014 levels.
- Pelican Lake operations averaged 50,818 bbl/d of annual heavy crude oil production, a 1% increase from 2014 levels. Canadian Natural continues to achieve success in developing, implementing and optimizing the leading edge polymer flood technology at Pelican Lake.
- Primary heavy crude oil annual production averaged 128,046 bbl/d, a decrease of 11%, as expected, from 2014 levels. This production decline reflects the Company's proactive decision to reduce its primary heavy crude oil drilling program by 88% year over year, and the Company's prudent decision to shut-in approximately 4,300 bbl/d of primary heavy crude oil production volumes during 2015 as a result of unfavorable economic conditions. In 2015, 108 net wells were drilled compared to 896 net wells in 2014.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Bitumen production (bbl/d)	**135,135**	133,183	118,974	**129,835**	107,802
Net wells targeting bitumen	**–**	–	–	**3**	15
Net successful wells drilled	**–**	–	–	**3**	15
Success rate	**–**	–	–	**100%**	100%

- In 2015, thermal in situ annual production achieved record volumes of 129,835 bbl/d, an increase of 20% from 2014 production volume levels. The increase in 2015 production reflects an 8% increase in production volumes from Primrose operations and an increase in Kirby South SAGD production volumes of 94%.
- At Kirby South, production volumes averaged 29,467 bbl/d in 2015 as operations continued its ramp-up to the targeted 40,000 bbl/d of design capacity. In November 2015, production exceeded 41,000 bbl/d which contributed to quarterly volumes of 33,746 bbl/d. The reservoir continues to perform as expected with very good thermal efficiencies.

Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Natural gas production (MMcf/d)	**1,635**	1,592	1,705	**1,663**	**1,527**
Net wells targeting natural gas	**4**	4	16	**19**	**76**
Net successful wells drilled	**4**	4	16	**19**	**75**
Success rate	**100%**	100%	100%	**100%**	**99%**

- North America natural gas annual production volumes averaged 1,663 MMcf/d for 2015, an increase of 9% from 2014 levels. The increase from 2014 to 2015 levels reflects strategic acquisitions partially offset by third party transportation restrictions in Alberta.
- Operations at Septimus, Canadian Natural's liquids-rich Montney natural gas play in British Columbia, continue to perform above expectations, with industry leading annual operating costs of $0.20/Mcfe in 2015.
- Canadian Natural's North America natural gas production volumes continued to be negatively impacted by transportation restrictions on the NOVA pipeline system in Q4/15 by 48 MMcf/d. In addition, the Company shut-in 50 MMcf/d of natural gas volumes related to low natural gas prices, driven largely by third party transmission pipeline restrictions in Northwest Alberta.
- Volumes will continue to be negatively affected in 2016 as a result of TransCanada's third party maintenance program on the NOVA pipeline system. Minor restrictions on the NOVA pipeline system are expected in Q1/16 and are reflected in Canadian Natural's Q1/16 total natural gas production guidance.
- North America natural gas annual operating costs were $1.27/Mcf in 2015, an 11% decrease from 2014 levels of $1.42/Mcf, reflecting a continued focus on cost optimization.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil production (bbl/d)					
North Sea	**23,110**	22,387	21,927	**22,216**	17,380
Offshore Africa	**24,832**	21,077	12,047	**19,079**	12,429
Natural gas production (MMcf/d)					
North Sea	**36**	35	10	**36**	7
Offshore Africa	**32**	26	18	**27**	21
Net wells targeting crude oil	**1.2**	2.6	1.0	**5.8**	4.5
Net successful wells drilled	**1.2**	2.6	1.0	**5.8**	4.5
Success rate	**100%**	100%	100%	**100%**	100%

- International crude oil production averaged 41,295 bbl/d during 2015, an increase of 39% from 2014 levels. The increase in 2015 production volumes over 2014 levels was primarily due to completion and tie-in of new wells at the Baobab and Espoir fields during the second half of 2015 and the reinstatement of production from both the Banff FPSO and the Tiffany platforms.

- During 2015, at the Espoir field, Côte d'Ivoire, the Company drilled 5 gross producing wells and 1 injector well, adding net production volumes of approximately 6,900 bbl/d to date. In 2016, upon completion of the sixth gross producing well, no additional wells will be drilled in the program. The infill drilling program is currently tracking to below its original sanction costs, and above original sanction production.

- During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 5 gross wells, adding net production volumes of approximately 13,400 bbl/d to date. In late December, the Baobab field was temporarily shut-in due to a riser failure, delaying first oil on the fifth gross well. After inspection of the riser system, production was reinstated in late January 2016. The drilling program is currently tracking to below its original sanction costs, and above original sanction production.

North America Oil Sands Mining and Upgrading – Horizon

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Synthetic crude oil production (bbl/d) (1)	**129,050**	131,779	128,090	**122,911**	110,571

(1) The Company produces diesel for internal use at Horizon. Fourth quarter 2015 SCO production before royalties excludes 2,337 bbl/d of SCO consumed internally as diesel (third quarter 2015 – 2,058 bbl/d; fourth quarter 2014 – 1,288 bbl/d; year ended December 31, 2015 – 2,122 bbl/d; year ended December 31, 2014 – 545 bbl/d).

- Horizon's strong performance during 2015 resulted in record production volumes of 122,911 bbl/d of SCO, an increase of 11% from 2014 levels. The increase in production volumes reflect safe, steady and reliable operations performed throughout the year offset by the 15 day planned maintenance turnaround completed in Q2/15.
- The Company achieved record annual operating costs at Horizon of $28.61/bbl (US$22.37/bbl equivalent) as a result of safe, steady and reliable operations and a focus on continuous improvement throughout 2015. In Q4/15, Horizon operating costs were $28.56/bbl (US$21.39/bbl equivalent), a 17% reduction from Q4/14 levels.
- Canadian Natural continues to execute on its strategy to transition to a longer life, low decline asset base while delivering significant and sustainable production. Canadian Natural's staged expansion of Horizon to 250,000 bbl/d of SCO production capacity continues to progress ahead of original schedule and below budget sanction. Canadian Natural has committed to approximately 85% of the Engineering, Procurement and Construction contracts with over 83% of the construction contracts awarded to date.

- As at December 31, 2015, physical progress of the Horizon project is updated below.
  - Directive 74 includes technological investment and research into tailings management. This project remains on track and is 59% physically complete.
  - Phase 2B is 79% physically complete. This Phase expands the capacity of major components such as gas/oil hydrotreatment, froth treatment and the hydrogen plant. Due to continued strong construction performance on the Horizon expansion, certain components of this project will be tied-in during the mid-2016 turnaround. The start-up of Horizon Phase 2B is targeted in 7 months and will add 45,000 bbl/d of production capacity.
  - Phase 3 is currently on budget and on schedule. This Phase is 74% physically complete, and includes the addition of extraction trains and combined hydrotreater. Phase 3 is targeted to increase production capacity by 80,000 bbl/d in Q4/17 and will result in additional reliability, redundancy and significant operating cost savings for the Horizon project.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 42.17**	$ 46.44	$ 73.12	**$ 48.76**	$ 92.92
WCS blend differential from WTI (%) (2)	**34%**	28%	20%	**28%**	21%
SCO price (US$/bbl)	**$ 42.77**	$ 45.78	$ 71.01	**$ 48.59**	$ 91.35
Condensate benchmark pricing (US$/bbl)	**$ 41.67**	$ 44.20	$ 70.54	**$ 47.34**	$ 92.84
Average realized pricing before risk management (C$/bbl) (3)	**$ 33.90**	$ 41.55	$ 62.80	**$ 41.13**	$ 77.04
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.51**	$ 2.65	$ 3.80	**$ 2.62**	$ 4.19
Average realized pricing before risk management (C$/Mcf)	**$ 2.96**	$ 3.22	$ 4.32	**$ 3.16**	$ 4.83

(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.

Benchmark Pricing	**WTI Pricing (US$/bbl)**	**WCS Blend Differential from WTI (%)**	**WCS Blend Differential from WTI (US$/bbl)**	**SCO Differential from WTI (US$/bbl)**	**Condensate Differential from WTI (US$/bbl)**	**1 CAD=X USD average exchange rate**
2015						
October	$ 46.29	29.2%	$ (13.51)	$ 0.11	$ (0.54)	$ 0.7649
November	$ 42.92	35.3%	$ (15.14)	$ 0.43	$ (1.12)	$ 0.7530
December	$ 37.33	39.7%	$ (14.82)	$ 1.25	$ 0.13	$ 0.7297
2016						
January	$ 31.78	43.7%	$ (13.90)	$ (0.03)	$ 2.85	$ 0.7031
February*	$ 30.62	46.7%	$ (14.32)	$ (0.46)	$ 1.25	$ 0.7250
March*	$ 34.33	43.3%	$ (14.50)	$ 1.20	$ (1.27)	$ 0.7412

**Based on current indicative pricing as at February 29, 2016. SCO and Condensate March pricing based on current indicative pricing as at February 29, 2016. Monthly USD/CAD exchange rates are based upon the average noon rates for each month. For March, the USD/CAD exchange rate was based upon the forward curve rate based on February 26, 2016 spot rate.*

- The 2015 annual average WTI price was US$48.76/bbl as compared to US$92.92/bbl in 2014. Q4/15 WTI pricing averaged US$42.17/bbl as compared to US$73.12/bbl in Q4/14. Volatility in supply and demand factors and geopolitical events remain primary factors in the current WTI and Brent pricing environment. The Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail oil production to offset the excess world supply resulted in a year over year decline in benchmark pricing.

- The WCS differential to WTI averaged US$13.51/bbl or 28% in 2015 compared to US$19.41/bbl or 21% in 2014. In Q4/15, the WCS differential to WTI averaged US$14.48/bbl or 34% as compared to Q4/14 of US$14.26/bbl or 20%. February 2016 and March 2016 indications of the WCS blend differential of US$14.32/bbl or 47% and US$14.50/bbl or 43% respectively, are normal given the trending WTI price curve. Seasonal demand fluctuations, changes in transportation logistics and refinery utilization and shutdowns will continue to be reflected in WCS pricing.
- Canadian Natural contributed approximately 183,000 bbl/d of its heavy crude oil stream to the WCS blend in 2015. The Company remains the largest contributor to the WCS blend, accounting for 49% of the total blend.
- SCO pricing averaged US$48.59/bbl during 2015 compared to US$91.35/bbl in 2014, a 47% decrease. Q4/15 SCO pricing averaged US$42.77/bbl in Q4/15 as compared to US$71.01/bbl in Q4/14 and US$45.78/bbl in Q3/15. Fluctuations in SCO pricing during Q4/15 were a result of changes in WTI benchmark pricing and unplanned industry-wide upgrader outages.
- AECO natural gas pricing in 2015 averaged $2.62/GJ, a decrease of 37% from 2014. Q4/15 AECO pricing averaged $2.51/GJ in Q4/15, decreasing by 34% and 5% from $3.80/GJ and $2.65/GJ in Q4/14 and Q3/15 respectively. In Q4/15, natural gas inventories reached new seasonal record levels as a result of warmer than normal winter temperatures in North America and higher US natural gas production relative to Q3/15 levels. 2015 natural gas pricing reflects lower demand due to warmer than normal winter temperatures in North America and higher than average storage levels relative to 2014.

NORTH WEST REDWATER UPGRADING AND REFINING

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: www.nwrpartnership.com/brief-updates.

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 and commodity hedging policy 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 851,901 BOE/d for 2015, with approximately 97% of total production located in G8 countries.
- Canadian Natural maintains significant financial stability and liquidity represented in part by bank credit facilities. As at December 31, 2015, the Company had in place bank credit facilities of $7,481 million, of which $3,495 million was available.
    - During the first two quarters of 2015, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018 and extended its two existing revolving syndicated term credit facilities to mature in June 2019 and June 2020. The result of the extension of the two revolving $2,425 million facilities netted an additional $350 million of liquidity. The Company's credit facilities all state that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 65%.
    - Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings from the $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. In addition the Company entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. Borrowings under this facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
- Canadian Natural maintained a strong balance sheet with debt to book capitalization of 38% at December 31, 2015.
- Subsequent to December 31, 2015, Standard & Poor's Rating Services maintained the Company's investment grade unsecured long-term and short-term credit ratings and DBRS Limited maintained the Company's investment grade unsecured long-term credit rating. Additionally, Moody's Investors Service, Inc. adjusted the Company's credit ratings within the investment grade debt rating scale.
- Canadian Natural declared a quarterly cash dividend on its common shares of C$0.23 per share payable on April 1, 2016. On an annualized basis, the dividend of C$0.92 per share remains unchanged from the previous annual dividend rate and reflects the Board of Director's confidence in the Company's cash flow.
- The Company has a strong balance sheet and cash flow generation which enables it to weather volatility in commodity prices. Canadian Natural retains additional capital expenditure program flexibility to proactively adapt to changing market conditions.

YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2015 the Company retained Independent Qualified Reserves Evaluators, Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. Sproule evaluated the Company's North America and International crude oil, bitumen, natural gas and NGL reserves. GLJ evaluated the Company's Horizon synthetic crude oil reserves. The Evaluators conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"). The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the Evaluators as to the Company's reserves. All reserve values are Company Gross unless stated otherwise.

Corporate Total

- Proved crude oil, SCO, bitumen and NGL reserves increased 4% to 4.70 billion barrels. Proved natural gas reserves increased 2% to 6.11 Tcf. Total proved reserves increased 4% to 5.71 billion BOE.
- Proved plus probable crude oil, SCO, bitumen and NGL reserves increased 1% to 7.62 billion barrels. Proved plus probable natural gas reserves increased 5% to 8.51 Tcf. Total proved plus probable reserves increased 2% to 9.04 billion BOE.
- Proved reserve additions and revisions, including acquisitions and dispositions, were 390 million barrels of crude oil, SCO, bitumen and NGL and 735 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio was 165%. The total proved BOE reserve life index is 21.5 years.
- Proved plus probable reserve additions and revisions, including acquisitions and dispositions, were 294 million barrels of crude oil, bitumen, SCO and NGL and 1.0 trillion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 148%. The total proved plus probable BOE reserve life index is 34.0 years.
- Proved undeveloped crude oil, SCO, bitumen and NGL reserves accounted for 25% of the corporate total proved reserves and proved undeveloped natural gas reserves accounted for 6% of the corporate total proved reserves.

North America Exploration and Production

- Proved crude oil, bitumen and NGL reserves decreased 1% to 2.04 billion barrels. Proved natural gas reserves increased 3% to 6.04 Tcf. Total proved BOE increased slightly from 3.03 billion barrels to 3.05 billion barrels.
- Proved plus probable crude oil, bitumen and NGL reserves increased 2% to 3.56 billion barrels. Proved plus probable natural gas reserves increased 5% to 8.34 Tcf. Total proved plus probable BOE increased 3% to 4.95 billion barrels.
- Proved reserve additions and revisions, including acquisitions and dispositions, were 132 million barrels of crude oil, bitumen and NGL and 776 billion cubic feet of natural gas. The total proved BOE reserve replacement ratio is 106%. The total proved BOE reserve life index in 14.5 years.
- Proved plus probable reserve additions and revisions, including acquisitions and dispositions, were 225 million barrels of crude oil, bitumen and NGL and 1,019 billion cubic feet of natural gas. The total proved plus probable BOE reserve replacement ratio was 160%. The total proved plus probable BOE reserve life index is 23.6 years.

North America Oil Sands Mining and Upgrading

- Proved SCO reserves increased 12% to 2.41 billion barrels, primarily due to a revised mine plan allowing mining to a Total Volume : Bitumen In Place ("TV:BIP") of 13 versus 12 in the original plan.

International Exploration and Production

- North Sea proved reserves decreased 24% to 165 million BOE. North Sea proved plus probable reserves decreased 8% to 300 million BOE.
- Offshore Africa proved reserves decreased 9% to 95 million BOE. Offshore Africa proved plus probable reserves decreased 7% to 154 million BOE.

Summary of Company Gross Reserves

As of December 31, 2015
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	102	112	222	351	2,283	3,848	99	3,810
Developed Non-Producing	8	20	4	–	–	270	6	83
Undeveloped	28	81	42	874	125	1,920	90	1,560
Total Proved	138	213	268	1,225	2,408	6,038	195	5,453
Probable	54	81	120	1,182	1,225	2,300	88	3,134
Total Proved plus Probable	192	294	388	2,407	3,633	8,338	283	8,587
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		23
Undeveloped	134					4		135
Total Proved	158					39		165
Probable	126					57		135
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	50					22		54
Developed Non-Producing	1					–		1
Undeveloped	39					7		40
Total Proved	90					29		95
Probable	52					45		59
Total Proved plus Probable	142					74		154
Total Company								
Proved								
Developed Producing	155	112	222	351	2,283	3,896	99	3,871
Developed Non-Producing	30	20	4	–	–	279	6	107
Undeveloped	201	81	42	874	125	1,931	90	1,735
Total Proved	386	213	268	1,225	2,408	6,106	195	5,713
Probable	232	81	120	1,182	1,225	2,402	88	3,328
Total Proved plus Probable	618	294	388	2,407	3,633	8,508	283	9,041

Summary of Company Net Reserves

As of December 31, 2015
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	90	96	168	276	1,926	3,495	73	3,211
Developed Non-Producing	7	16	3	–	–	239	5	71
Undeveloped	25	69	33	700	87	1,649	71	1,260
Total Proved	122	181	204	976	2,013	5,383	149	4,542
Probable	45	66	82	908	993	1,978	67	2,491
Total Proved plus Probable	167	247	286	1,884	3,006	7,361	216	7,033
North Sea								
Proved								
Developed Producing	3					26		7
Developed Non-Producing	21					9		22
Undeveloped	134					4		135
Total Proved	158					39		164
Probable	126					57		136
Total Proved plus Probable	284					96		300
Offshore Africa								
Proved								
Developed Producing	43					15		46
Developed Non-Producing	–					–		–
Undeveloped	31					6		32
Total Proved	74					21		78
Probable	39					29		43
Total Proved plus Probable	113					50		121
Total Company								
Proved								
Developed Producing	136	96	168	276	1,926	3,536	73	3,264
Developed Non-Producing	28	16	3	–	–	248	5	93
Undeveloped	190	69	33	700	87	1,659	71	1,427
Total Proved	354	181	204	976	2,013	5,443	149	4,784
Probable	210	66	82	908	993	2,064	67	2,670
Total Proved plus Probable	564	247	286	1,884	3,006	7,507	216	7,454

Reconciliation of Company Gross Reserves

As of December 31, 2015
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	145	229	274	1,217	2,158	5,869	188	5,189
Discoveries	1	–	–	–	–	14	2	5
Extensions	1	4	–	23	220	252	10	300
Infill Drilling	4	10	–	–	–	298	7	71
Improved Recovery	–	–	2	26	–	–	–	28
Acquisitions	5	4	–	7	–	414	8	93
Dispositions	(3)	–	–	–	–	(7)	–	(4)
Economic Factors	(6)	(3)	–	–	7	(385)	(6)	(72)
Technical Revisions	10	16	10	(1)	68	190	1	135
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	138	213	268	1,225	2,408	6,038	195	5,453

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	204	83	218
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(2)	(7)	(3)
Technical Revisions	(36)	(24)	(40)
Production	(8)	(13)	(10)
December 31, 2015	158	39	165

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	96	49	104
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	1	–	1
Technical Revisions	–	(10)	(1)
Production	(7)	(10)	(9)
December 31, 2015	90	29	95

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	445	229	274	1,217	2,158	6,001	188	5,511
Discoveries	1	–	–	–	–	14	2	5
Extensions	1	4	–	23	220	252	10	300
Infill Drilling	4	10	–	–	–	298	7	71
Improved Recovery	–	–	2	26	–	–	–	28
Acquisitions	5	4	–	7	–	414	8	93
Dispositions	(3)	–	–	–	–	(7)	–	(4)
Economic Factors	(7)	(3)	–	–	7	(392)	(6)	(74)
Technical Revisions	(26)	16	10	(1)	68	156	1	94
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	386	213	268	1,225	2,408	6,106	195	5,713

Reconciliation of Company Gross Reserves

As of December 31, 2015
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	58	88	121	1,095	1,435	2,057	70	3,210
Discoveries	–	–	–	–	–	3	–	1
Extensions	1	2	–	88	(175)	106	5	(61)
Infill Drilling	4	3	–	–	–	444	22	103
Improved Recovery	–	–	1	14	–	1	–	15
Acquisitions	1	1	–	2	–	101	2	23
Dispositions	(2)	–	–	–	–	(2)	–	(3)
Economic Factors	–	–	–	–	–	(117)	(2)	(22)
Technical Revisions	(8)	(13)	(2)	(17)	(35)	(293)	(9)	(132)
Production	–	–	–	–	–	–	–	–
December 31, 2015	54	81	120	1,182	1,225	2,300	88	3,134

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	104	31	109
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	–	7	1
Technical Revisions	22	19	25
Production	–	–	–
December 31, 2015	126	57	135

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	53	49	61
Discoveries	–	–	–
Extensions	–	–	–
Infill Drilling	–	–	–
Improved Recovery	–	–	–
Acquisitions	–	–	–
Dispositions	–	–	–
Economic Factors	(1)	1	(1)
Technical Revisions	–	(5)	(1)
Production	–	–	–
December 31, 2015	52	45	59

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	215	88	121	1,095	1,435	2,137	70	3,380
Discoveries	–	–	–	–	–	3	–	1
Extensions	1	2	–	88	(175)	106	5	(61)
Infill Drilling	4	3	–	–	–	444	22	103
Improved Recovery	–	–	1	14	–	1	–	15
Acquisitions	1	1	–	2	–	101	2	23
Dispositions	(2)	–	–	–	–	(2)	–	(3)
Economic Factors	(1)	–	–	–	–	(109)	(2)	(22)
Technical Revisions	14	(13)	(2)	(17)	(35)	(279)	(9)	(108)
Production	–	–	–	–	–	–	–	–
December 31, 2015	232	81	120	1,182	1,225	2,402	88	3,328

Reconciliation of Company Gross Reserves

As of December 31, 2015
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2014	203	317	395	2,312	3,593	7,926	258	8,399
Discoveries	1	–	–	–	–	17	2	6
Extensions	2	6	–	111	45	358	15	239
Infill Drilling	8	13	–	–	–	742	29	174
Improved Recovery	–	–	3	40	–	1	–	43
Acquisitions	6	5	–	9	–	515	10	116
Dispositions	(5)	–	–	–	–	(9)	–	(7)
Economic Factors	(6)	(3)	–	–	7	(502)	(8)	(94)
Technical Revisions	2	3	8	(18)	33	(103)	(8)	3
Production	(19)	(47)	(18)	(47)	(45)	(607)	(15)	(292)
December 31, 2015	192	294	388	2,407	3,633	8,338	283	8,587

North Sea

December 31, 2014	308					114		327
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	(2)					–		(2)
Technical Revisions	(14)					(5)		(15)
Production	(8)					(13)		(10)
December 31, 2015	284					96		300

Offshore Africa

December 31, 2014	149					98		165
Discoveries	–					–		–
Extensions	–					–		–
Infill Drilling	–					–		–
Improved Recovery	–					–		–
Acquisitions	–					–		–
Dispositions	–					–		–
Economic Factors	–					1		–
Technical Revisions	–					(15)		(2)
Production	(7)					(10)		(9)
December 31, 2015	142					74		154

Total Company

December 31, 2014	660	317	395	2,312	3,593	8,138	258	8,891
Discoveries	1	–	–	–	–	17	2	6
Extensions	2	6	–	111	45	358	15	239
Infill Drilling	8	13	–	–	–	742	29	174
Improved Recovery	–	–	3	40	–	1	–	43
Acquisitions	6	5	–	9	–	515	10	116
Dispositions	(5)	–	–	–	–	(9)	–	(7)
Economic Factors	(8)	(3)	–	–	7	(501)	(8)	(96)
Technical Revisions	(12)	3	8	(18)	33	(123)	(8)	(14)
Production	(34)	(47)	(18)	(47)	(45)	(630)	(15)	(311)
December 31, 2015	618	294	388	2,407	3,633	8,508	283	9,041

Reserves Notes:

(1) Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.

(2) Company Net reserves are working interest share after deduction of royalties and including any royalty interests.

(3) BOE values may not calculate due to rounding.

(4) Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserve estimates were provided by Sproule Associates Limited:

	2016	2017	2018	2019	2020	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Western Canada Select (C$/bbl)	$ 45.26	$ 57.96	$ 65.88	$ 75.11	$ 77.03	1.50%
Canadian Light Sweet (C$/bbl)	$ 55.20	$ 69.00	$ 78.43	$ 89.41	$ 91.71	1.50%
Cromer LSB (C$/bbl)	$ 54.20	$ 68.00	$ 77.43	$ 88.41	$ 90.71	1.50%
Edmonton Pentanes+ (C$/bbl)	$ 59.10	$ 73.88	$ 83.98	$ 95.73	$ 98.19	1.50%
North Sea Brent (US$/bbl)	$ 45.00	$ 60.00	$ 70.00	$ 80.00	$ 81.20	1.50%
Natural gas						
AECO (C$/MMBtu)	$ 2.25	$ 2.95	$ 3.42	$ 3.91	$ 4.20	1.50%
BC Westcoast Station 2 (C$/MMBtu)	$ 1.45	$ 2.55	$ 3.02	$ 3.51	$ 3.80	1.50%
Henry Hub Louisiana (US$/MMBtu)	$ 2.25	$ 3.00	$ 3.50	$ 4.00	$ 4.25	1.50%

A foreign exchange rate of 0.7500 US$/C$ for 2016, 0.8000 US$/C$ for 2017, 0.8300 US$/C$ for 2018 and 0.8500 US$/C$ after 2018 was used in the 2015 evaluation.

(5) Reserve additions and revisions are comprised of all categories of Company Gross reserve changes, exclusive of production.

(6) Reserve replacement ratio is the Company Gross reserve additions and revisions, for the relevant reserve category, divided by the Company Gross production in the same period.

(7) Reserve Life Index is based on the amount for the relevant reserve category divided by the 2016 proved developed producing production forecast prepared by the Independent Qualified Reserve Evaluators.

(8) Finding, Development and Acquisition (FD&A) costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2015 by the sum of total additions and revisions for the relevant reserve category.

(9) FD&A costs including change in Future Development Capital (FDC) are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2015 and net change in FDC from December 31, 2014 to December 31, 2015 by the sum of total additions and revisions for the relevant reserve category. FDC excludes all abandonment and reclamation costs.

(10) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel 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.

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 their 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, 2015 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

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, 2015 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 from operations, 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, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. 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, 2015 in relation to the comparable periods in 2014 and the third quarter of 2015. 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, 2014, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated March 2, 2016.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Product sales	**$ 2,963**	$ 3,316	$ 4,850	**$ 13,167**	$ 21,301
Net earnings (loss)	**$ 131**	$ (111)	$ 1,198	**$ (637)**	$ 3,929
Per common share – basic	**$ 0.12**	$ (0.10)	$ 1.10	**$ (0.58)**	$ 3.60
– diluted	**$ 0.12**	$ (0.10)	$ 1.09	**$ (0.58)**	$ 3.58
Adjusted net earnings (loss) from operations[(1)]	**$ (49)**	$ 113	$ 756	**$ 263**	$ 3,811
Per common share – basic	**$ (0.04)**	$ 0.10	$ 0.69	**$ 0.24**	$ 3.49
– diluted	**$ (0.04)**	$ 0.10	$ 0.69	**$ 0.24**	$ 3.47
Cash flow from operations [(2)]	**$ 1,379**	$ 1,533	$ 2,368	**$ 5,785**	$ 9,587
Per common share – basic	**$ 1.26**	$ 1.40	$ 2.17	**$ 5.29**	$ 8.78
– diluted	**$ 1.26**	$ 1.40	$ 2.16	**$ 5.28**	$ 8.74
Capital expenditures, net of dispositions	**$ (96)**	$ 1,240	$ 2,220	**$ 3,853**	$ 11,744

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings adjusted for certain items of a non-operational nature. The Company evaluates its performance based on adjusted net earnings from operations. The reconciliation "Adjusted Net Earnings 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 from operations may not be comparable to similar measures presented by other companies.

(2) Cash flow from operations is a non-GAAP measure that represents net earnings adjusted for non-cash items before working capital adjustments. The Company evaluates its performance based on cash flow from operations. The Company considers cash 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 "Cash Flow from Operations" presents certain non-cash items that are included in the Company's financial results. Cash flow from operations may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (loss) from Operations

($ millions)	Three Months Ended Dec 31 2015	Sep 30 2015	Dec 31 2014	Year Ended Dec 31 2015	Dec 31 2014
Net earnings (loss) as reported	**$ 131**	$ (111)	$ 1,198	**$ (637)**	$ 3,929
Share-based compensation, net of tax (1)	**56**	(87)	(144)	**(46)**	66
Unrealized risk management loss (gain), net of tax (2)	**128**	(24)	(303)	**275**	(339)
Unrealized foreign exchange loss , net of tax (3)	**170**	351	106	**858**	256
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**–**	–	36	**–**	36
Loss from investments, net of tax (5)(6)	**23**	20	–	**55**	–
Gains on disposition of properties and corporate acquisitions, net of tax (7)	**(627)**	(36)	(137)	**(663)**	(137)
Derecognition of exploration and evaluation assets, net of tax (8)	**70**	–	–	**70**	–
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (9)	**–**	–	–	**351**	–
Adjusted net earnings (loss) from operations	**$ (49)**	$ 113	$ 756	**$ 263**	$ 3,811

(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 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. 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.

(4) During the fourth quarter of 2014, the Company repaid US$500 million of 1.45% notes and US$350 million of 4.90% notes.

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

(6) The Company's investment in PrairieSky Royalty Ltd. ("PrairieSky") has been accounted for at fair value through profit and loss and is remeasured each period with changes in fair value recognized in net earnings.

(7) 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. During the fourth quarter of 2014, the Company recorded an after-tax gain of $137 million related to the acquisition of certain producing crude oil and natural gas properties.

(8) 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.

(9) 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. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $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 Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

Cash Flow from Operations

($ millions)	Three Months Ended Dec 31 2015	Sep 30 2015	Dec 31 2014	Year Ended Dec 31 2015	Dec 31 2014
Net earnings (loss)	**$ 131**	$ (111)	$ 1,198	**$ (637)**	$ 3,929
Non-cash items:					
Depletion, depreciation and amortization	**1,472**	1,376	1,406	**5,483**	4,880
Share-based compensation	**56**	(87)	(144)	**(46)**	66
Asset retirement obligation accretion	**43**	44	49	**173**	193
Unrealized risk management loss (gain)	**174**	(29)	(404)	**374**	(451)
Unrealized foreign exchange loss	**170**	351	106	**858**	256
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax	**–**	–	36	**–**	36
Loss from investments	**23**	20	5	**55**	8
Deferred income tax (recovery) expense	**(33)**	18	253	**231**	807
Gains on disposition of properties and corporate acquisitions	**(690)**	(49)	(137)	**(739)**	(137)
Current income tax on disposition of properties	**33**	–	–	**33**	–
Cash flow from operations	**$ 1,379**	$ 1,533	$ 2,368	**$ 5,785**	$ 9,587

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

The net loss for the year ended December 31, 2015 was $637 million compared with net earnings of $3,929 million for the year ended December 31, 2014. Net loss for the year ended December 31, 2015 included net after-tax expenses of $900 million compared with net after-tax income of $118 million for the year ended December 31, 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on the repayment of long term debt, loss from investments, gains on disposition of properties and corporate acquisitions, 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 year ended December 31, 2015 were $263 million compared with $3,811 million for the year ended December 31, 2014.

Net earnings for the fourth quarter of 2015 was $131 million compared with net earnings of $1,198 million for the fourth quarter of 2014 and net loss of $111 million for the third quarter of 2015. Net earnings for the fourth quarter of 2015 included net after-tax income of $180 million compared with net after-tax income of $442 million for the fourth quarter of 2014 and net after-tax expenses of $224 million for the third quarter of 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of a realized foreign exchange gain on the repayment of long term debt, loss from investments, gains on disposition of properties and corporate acquisitions 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 fourth quarter of 2015 was $49 million compared with adjusted net earnings of $756 million for the fourth quarter of 2014 and adjusted net earnings of $113 million for the third quarter of 2015.

The decrease in adjusted net earnings for the year ended December 31, 2015 from the comparable period in 2014 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices;
- lower natural gas netbacks in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and NGLs, SCO and natural gas sales volumes across all segments;
- higher realized risk management gains; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the fourth quarter of 2015 from the fourth quarter of 2014 was primarily due to:

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

partially offset by:

- higher crude oil and NGLs sales volumes in the International segments; and
- the impact of a weaker Canadian dollar relative to the US dollar.

The decrease in adjusted net earnings for the fourth quarter of 2015 from the third quarter of 2015 was primarily due to:

- lower crude oil and NGLs netbacks in the Exploration and Production segments;
- lower realized SCO prices; and
- lower crude oil and NGLs sales volumes in the North America segment.

partially offset by:

- higher crude oil and NGLs sales volumes in the International segments; and
- the impact of a weaker Canadian dollar relative to the US dollar.

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

Cash flow from operations for the year ended December 31, 2015 was $5,785 million compared with $9,587 million for the year ended December 31, 2014. Cash flow from operations for the fourth quarter of 2015 was $1,379 million compared with $2,368 million for the fourth quarter of 2014 and $1,533 million for the third quarter of 2015. The fluctuations in cash flow from operations from the comparable periods were primarily due to the factors noted above relating to the decrease in adjusted net earnings, as well as due to the impact of cash taxes.

Total production before royalties for the year ended December 31, 2015 increased 8% to 851,901 BOE/d from 790,410 BOE/d for the year ended December 31, 2014. Total production before royalties for the fourth quarter of 2015 of 855,800 BOE/d was consistent with production of 860,920 BOE/d in the fourth quarter of 2014 and 848,701 BOE/d in the third quarter of 2015.

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 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)

($ millions, except per common share amounts)	Dec 31 2014	Sep 30 2014	Jun 30 2014	Mar 31 2014
Product sales	$ 4,850	$ 5,370	$ 6,113	$ 4,968
Net earnings (loss)	$ 1,198	$ 1,039	$ 1,070	$ 622
Net earnings (loss) per common share				
– basic	$ 1.10	$ 0.95	$ 0.98	$ 0.57
– diluted	$ 1.09	$ 0.94	$ 0.97	$ 0.57

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

- **Crude oil pricing** – The impact of increased shale oil production in North America, fluctuating global supply/demand including the Organization of the Petroleum Exporting Countries' ("OPEC") decision not to curtail crude oil production to offset the excess 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 Dated 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 increased 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, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, the impact of turnarounds at Horizon and higher drilling in Côte d'Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the North Sea and Offshore Africa.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, as well as natural decline rates, shut-in natural gas production due to third party pipeline restrictions and related pricing impacts, 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, and turnarounds at Horizon.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions, 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 commodity volumes hedged and 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 predominately 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 corporate acquisitions** – Fluctuations due to the recognition of gains on disposition of properties in the third and fourth quarters of 2015 and acquisitions in the fourth quarter of 2014.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
WTI benchmark price (US$/bbl)	**$ 42.17**	$ 46.44	$ 73.12	**$ 48.76**	$ 92.92
Dated Brent benchmark price (US$/bbl)	**$ 43.59**	$ 50.39	$ 75.99	**$ 52.40**	$ 98.85
WCS blend differential from WTI (US$/bbl)	**$ 14.48**	$ 13.21	$ 14.26	**$ 13.51**	$ 19.41
WCS blend differential from WTI (%)	**34%**	28%	20%	**28%**	21%
SCO price (US$/bbl)	**$ 42.77**	$ 45.78	$ 71.01	**$ 48.59**	$ 91.35
Condensate benchmark price (US$/bbl)	**$ 41.67**	$ 44.20	$ 70.54	**$ 47.34**	$ 92.84
NYMEX benchmark price (US$/MMBtu)	**$ 2.28**	$ 2.77	$ 3.95	**$ 2.67**	$ 4.37
AECO benchmark price (C$/GJ)	**$ 2.51**	$ 2.65	$ 3.80	**$ 2.62**	$ 4.19
US/Canadian dollar average exchange rate (US$)	**$ 0.7489**	$ 0.7640	$ 0.8806	**$ 0.7820**	$ 0.9054

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 prices are highly sensitive to fluctuations in foreign exchange rates. For the three months and year ended December 31, 2015, realized prices continued to be supported by the weaker Canadian dollar, which increased the Canadian dollar sales price the Company received for its crude oil and natural gas sales, as realized pricing 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$48.76 per bbl for the year ended December 31, 2015, a decrease of 48% from US$92.92 per bbl for the year ended December 31, 2014. WTI averaged US$42.17 per bbl for the fourth quarter of 2015, a decrease of 42% from US$73.12 per bbl for the fourth quarter of 2014, and a decrease of 9% from US$46.44 per bbl for the third quarter of 2015.

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$52.40 per bbl for the year ended December 31, 2015, a decrease of 47% from US$98.85 per bbl for the year ended December 31, 2014. Brent averaged US$43.59 per bbl for the fourth quarter of 2015, a decrease of 43% from US$75.99 per bbl for the fourth quarter of 2014, and a decrease of 13% from US$50.39 per bbl for the third quarter of 2015.

WTI and Brent pricing continued to reflect volatility in supply and demand factors and geopolitical events. An oversupply of crude oil in the world market contributed to a further decrease in crude oil benchmark pricing in the fourth quarter of 2015. OPECs' decision not to curtail crude oil production to offset the excess world supply continues to put downward pressure on benchmark pricing.

The WCS Heavy Differential percentage averaged 28% for the year ended December 31, 2015, compared with 21% for the year ended December 31, 2014. The WCS Heavy Differential averaged 34% for the fourth quarter of 2015 compared with 20% for the fourth quarter of 2014 and 28% for the third quarter of 2015. Fluctuations in the WCS Heavy Differential reflect seasonal demand, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US$48.59 per bbl for the year ended December 31, 2015, a decrease of 47% from US$91.35 per bbl for the year ended December 31, 2014. The SCO price averaged US$42.77 per bbl for the fourth quarter of 2015, a decrease of 40% from US$71.01 per bbl for the fourth quarter of 2014, and a decrease of 7% from US$45.78 per bbl for the third quarter of 2015. The fluctuations in SCO pricing for the three months and year ended December 31, 2015 from the comparable periods were primarily due to changes in WTI benchmark pricing and the impact of industry wide unplanned upgrader outages.

NYMEX natural gas prices averaged US$2.67 per MMBtu for the year ended December 31, 2015, a decrease of 39% from US$4.37 per MMBtu for the year ended December 31, 2014. NYMEX natural gas prices averaged US$2.28 per MMBtu for the fourth quarter of 2015, a decrease of 42% from US$3.95 per MMBtu for the fourth quarter of 2014, and a decrease of 18% from US$2.77 per MMBtu for the third quarter of 2015.

AECO natural gas prices for the year ended December 31, 2015 averaged $2.62 per GJ, a decrease of 37% from $4.19 per GJ for the year ended December 31, 2014. AECO natural gas prices for the fourth quarter of 2015 averaged $2.51 per GJ, a decrease of 34% from $3.80 per GJ for the fourth quarter of 2014, and a decrease of 5% from $2.65 per GJ for the third quarter of 2015.

The decrease in natural gas prices in the fourth quarter of 2015 compared to the third quarter of 2015 was primarily due to US natural gas inventories reaching a new seasonal record level as a result of strong natural gas production volumes together with warmer than normal winter temperatures in the fourth quarter of 2015. Natural gas prices were lower in the fourth quarter of 2015 compared with the fourth quarter of 2014 reflecting lower demand as North America experienced warmer than normal winter temperatures in 2015. In addition, 2014 prices were higher due to lower than average storage levels in 2014 due to colder than normal winter temperatures.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**395,008**	397,892	409,976	**399,982**	390,814
North America – Oil Sands Mining and Upgrading [1]	**129,050**	131,779	128,090	**122,911**	110,571
North Sea	**23,110**	22,387	21,927	**22,216**	17,380
Offshore Africa	**24,832**	21,077	12,047	**19,079**	12,429
	572,000	573,135	572,040	**564,188**	531,194
Natural gas (MMcf/d)					
North America	**1,635**	1,592	1,705	**1,663**	1,527
North Sea	**36**	35	10	**36**	7
Offshore Africa	**32**	26	18	**27**	21
	1,703	1,653	1,733	**1,726**	1,555
Total barrels of oil equivalent (BOE/d)	**855,800**	848,701	860,920	**851,901**	790,410
Product mix					
Light and medium crude oil and NGLs	**16%**	15%	15%	**16%**	15%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**14%**	15%	17%	**15%**	18%
Bitumen (thermal oil)	**16%**	16%	14%	**15%**	14%
Synthetic crude oil [1]	**15%**	16%	15%	**14%**	14%
Natural gas	**33%**	32%	33%	**34%**	33%
Percentage of product sales [1] [2] (excluding Midstream revenue)					
Crude oil and NGLs	**82%**	83%	84%	**82%**	85%
Natural gas	**18%**	17%	16%	**18%**	15%

(1) Fourth quarter 2015 SCO production before royalties excludes 2,337 bbl/d of SCO consumed internally as diesel (third quarter 2015 – 2,058 bbl/d; fourth quarter 2014 – 1,288 bbl/d; year ended December 31, 2015 – 2,122 bbl/d; year ended December 31, 2014 – 545 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**345,027**	350,444	343,324	**350,451**	318,291
North America – Oil Sands Mining and Upgrading	**127,968**	129,355	121,292	**121,208**	104,095
North Sea	**23,054**	22,325	21,881	**22,164**	17,313
Offshore Africa	**23,620**	20,145	11,203	**18,209**	11,500
	519,669	522,269	497,700	**512,032**	451,199
Natural gas (MMcf/d)					
North America	**1,568**	1,527	1,606	**1,606**	1,407
North Sea	**36**	35	10	**36**	7
Offshore Africa	**30**	25	16	**25**	18
	1,634	1,587	1,632	**1,667**	1,432
Total barrels of oil equivalent (BOE/d)	**792,083**	786,734	769,775	**789,799**	689,893

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, 2015 increased 6% to 564,188 bbl/d from 531,194 bbl/d for the year ended December 31, 2014. Crude oil and NGLs production for the fourth quarter of 2015 of 572,000 bbl/d was comparable to both the fourth quarter of 2014 and the third quarter of 2015. The increase in production for the year ended December 31, 2015 was primarily due to increased production in the Horizon and International segments as well as from acquisitions of producing Canadian crude oil properties in 2014. Crude oil and NGLs production for the year ended December 31, 2015 was within the Company's previously issued guidance of 555,000 to 591,000 bbl/d.

Natural gas production for the year ended December 31, 2015 increased 11% to 1,726 MMcf/d from 1,555 MMcf/d for the year ended December 31, 2014. Natural gas production for the fourth quarter of 2015 decreased 2% to 1,703 MMcf/d from 1,733 MMcf/d for the fourth quarter of 2014 and increased 3% from 1,653 MMcf/d for the third quarter of 2015. The increase in natural gas production for the year ended December 31, 2015 from the comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014 and growth in production volumes in the North Sea. Annual 2015 natural gas production reflected the impact of third party pipeline transportation restrictions in Northwest Alberta during the second half of 2015, including both temporary and permanent shut-in of volumes in the fourth quarter of 2015 due to the impact of low natural gas prices resulting from these restrictions.

During the fourth quarter of 2015, the Company shut-in approximately 48 MMcf/d related to the impact of pipeline transportation restrictions (approximately 105 MMcf/d in the third quarter of 2015) together with approximately 50 MMcf/d of additional natural gas volumes due to the impact of low natural gas prices resulting from these restrictions. These factors resulted in natural gas production of 1,726 MMcf/d for the year ended December 31, 2015, slightly below the Company's previously issued guidance of 1,730 to 1,770 MMcf/d.

For 2016 annual production guidance is now targeted to average between 514,000 and 563,000 bbl/d of crude oil and NGLs and between 1,770 and 1,830 MMcf/d of natural gas. First quarter 2016 production guidance is targeted to average between 532,000 and 557,000 bbl/d of crude oil and NGLs and between 1,780 and 1,820 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2015 increased 2% to average 399,982 bbl/d from 390,814 bbl/d for the year ended December 31, 2014. For the fourth quarter of 2015, crude oil and NGLs production decreased 4% to average 395,008 bbl/d compared with 409,976 bbl/d for the fourth quarter of 2014 and was comparable with the third quarter of 2015. The increase in production for the year ended December 31, 2015 from the comparable period was primarily due to increased production in the Company's thermal areas, including Kirby South, and increased production related to the acquisitions of producing Canadian crude oil properties in 2014. The decrease in production from the three months ended December 31, 2015 compared with the comparable period in 2014 primarily reflected lower drilling activity in 2015 than the comparable period and natural field declines, partially offset by optimization activities in various fields. Annual 2015 production of crude oil and NGLs was within the Company's previously issued guidance of 393,000 to 413,000 bbl/d. First quarter 2016 production guidance is targeted to average between 363,000 and 377,000 bbl/d of crude oil and NGLs.

Natural gas production for the year ended December 31, 2015 increased 9% to 1,663 MMcf/d compared with 1,527 MMcf/d for the year ended December 31, 2014. Natural gas production decreased 4% to 1,635 MMcf/d for the fourth quarter of 2015 compared with 1,705 MMcf/d in the fourth quarter of 2014 and increased 3% from 1,592 for the third quarter of 2015. The increase in natural gas production for the year ended December 31, 2015 from the comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014. Annual 2015 natural gas production reflected the impact of third party pipeline transportation restrictions in Northwest Alberta during the second half of 2015, including both temporary and permanent shut-in of volumes in the fourth quarter of 2015 due to the impact of low natural gas prices resulting from these restrictions.

During the fourth quarter of 2015, the Company shut-in approximately 48 MMcf/d related to the impact of pipeline transportation restrictions (approximately 105 MMcf/d in the third quarter of 2015) together with approximately 50 MMcf/d of additional natural gas volumes due to the impact of low natural gas prices resulting from these restrictions. These factors resulted in natural gas production of 1,726 MMcf/d for the year ended December 31, 2015, slightly below the Company's previously issued guidance of 1,730 to 1,770 MMcf/d.

North America – Oil Sands Mining and Upgrading

SCO production for the year ended December 31, 2015 increased 11% to average 122,911 bbl/d compared with 110,571 bbl/d for the year ended December 31, 2014. For the fourth quarter of 2015, SCO production of 129,050 bbl/d was comparable with both the fourth quarter of 2014 and the third quarter of 2015. Production in the fourth quarter of 2015 continued to reflect high utilization rates and reliability, following the completion of the planned turnaround in the second quarter of 2015 and the coker expansion tie-in during the third quarter of 2014. Annual 2015 production of SCO was within the Company's previously issued guidance of 121,000 to 131,000 bbl/d. First quarter 2016 production guidance is targeted to average between 122,000 and 128,000 bbl/d.

North Sea

North Sea crude oil production for the year ended December 31, 2015 increased 28% to 22,216 bbl/d from 17,380 bbl/d for the year ended December 31, 2014. Fourth quarter 2015 crude oil production increased 5% to 23,110 bbl/d from 21,927 bbl/d for the fourth quarter of 2014, and increased 3% from 22,387 bbl/d for the third quarter of 2015. The increase in production for the three months and year ended December 31, 2015 from the comparable periods primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014 and the impact of planned turnarounds completed at the Ninian platforms early in the third quarter of 2015.

Offshore Africa

Offshore Africa crude oil production increased 54% to 19,079 bbl/d for the year ended December 31, 2015 from 12,429 bbl/d for the year ended December 31, 2014. Fourth quarter 2015 crude oil production increased 106% to 24,832 bbl/d from 12,047 bbl/d for the fourth quarter of 2014 and increased 18% from 21,077 bbl/d for the third quarter of 2015. Production volumes increased for the three months and year ended December 31, 2015 as new wells came on stream at both the Espoir and the Baobab fields throughout 2015, partially offset by natural field declines. In late December 2015, the Baobab field was temporarily shut-in due to a riser failure, and after inspection of the riser system, production was reinstated in late January 2016.

International Guidance

Annual international crude oil production was within the Company's previously issued guidance of 41,000 to 47,000 bbl/d.

First quarter 2016 production guidance is targeted to average between 47,000 and 52,000 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 2015**	Sep 30 2015	Dec 31 2014
North Sea	**835,806**	450,023	368,808
Offshore Africa	**1,271,170**	1,353,011	461,997
	2,106,976	1,803,034	830,805

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 33.90**	$ 41.55	$ 62.80	**$ 41.13**	$ 77.04
Transportation	**2.61**	2.56	2.15	**2.60**	2.41
Realized sales price, net of transportation	**31.29**	38.99	60.65	**38.53**	74.63
Royalties	**3.49**	4.09	9.05	**4.30**	12.99
Production expense	**14.26**	15.70	18.69	**15.74**	18.25
Netback	**$ 13.54**	$ 19.20	$ 32.91	**$ 18.49**	$ 43.39
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.96**	$ 3.22	$ 4.32	**$ 3.16**	$ 4.83
Transportation	**0.38**	0.39	0.28	**0.38**	0.27
Realized sales price, net of transportation	**2.58**	2.83	4.04	**2.78**	4.56
Royalties	**0.10**	0.11	0.24	**0.10**	0.38
Production expense	**1.22**	1.31	1.39	**1.34**	1.48
Netback	**$ 1.26**	$ 1.41	$ 2.41	**$ 1.34**	$ 2.70
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 27.79**	$ 33.46	$ 48.23	**$ 32.60**	$ 58.48
Transportation	**2.59**	2.56	2.05	**2.56**	2.18
Realized sales price, net of transportation	**25.20**	30.90	46.18	**30.04**	56.30
Royalties	**2.38**	2.81	6.10	**2.85**	8.90
Production expense	**11.55**	12.68	14.66	**12.70**	14.67
Netback	**$ 11.27**	$ 15.41	$ 25.42	**$ 14.49**	$ 32.73

(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 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 31.51**	$ 39.26	$ 61.28	**$ 38.96**	$ 75.09
North Sea	**$ 57.50**	$ 62.28	$ 83.32	**$ 65.13**	$ 106.63
Offshore Africa	**$ 53.37**	$ 65.31	$ 68.90	**$ 63.13**	$ 97.81
Company average	**$ 33.90**	$ 41.55	$ 62.80	**$ 41.13**	$ 77.04
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.73**	$ 2.99	$ 4.22	**$ 2.91**	$ 4.72
North Sea	**$ 9.53**	$ 9.44	$ 8.22	**$ 9.66**	$ 7.07
Offshore Africa	**$ 7.63**	$ 9.01	$ 11.73	**$ 9.53**	$ 11.98
Company average	**$ 2.96**	$ 3.22	$ 4.32	**$ 3.16**	$ 4.83
Company average ($/BOE) (1) (2)	**$ 27.79**	$ 33.46	$ 48.23	**$ 32.60**	$ 58.48

(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 48% to average $38.96 per bbl for the year ended December 31, 2015 from $75.09 per bbl for the year ended December 31, 2014. North America realized crude oil prices averaged $31.51 per bbl for the fourth quarter of 2015, a decrease of 49% compared with $61.28 per bbl for the fourth quarter of 2014 and a decrease of 20% compared with $39.26 per bbl for the third quarter of 2015. The decrease in realized crude oil prices for the three months and year ended December 31, 2015 from the comparable periods was primarily due to lower WTI benchmark pricing and a widening WCS Heavy Differential as a percentage of WTI, partially offset by the impact of a weakening Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2015 contributed approximately 224,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 38% to average $2.91 per Mcf for the year ended December 31, 2015 from $4.72 per Mcf for the year ended December 31, 2014. North America realized natural gas prices decreased 35% to average $2.73 per Mcf for the fourth quarter of 2015 compared with $4.22 per Mcf in the fourth quarter of 2014, and decreased 9% compared with $2.99 per Mcf for the third quarter of 2015.

The decrease in natural gas prices in the fourth quarter of 2015 compared to the third quarter of 2015 was primarily due to US natural gas inventories reaching a new seasonal record level as a result of strong natural gas production volumes and warmer than normal winter temperatures in the fourth quarter of 2015. Natural gas prices were lower in the fourth quarter of 2015 compared with the fourth quarter of 2014 reflecting lower demand as North America experienced warmer than normal winter temperatures in 2015. In addition, 2014 prices were higher due to lower than average storage levels in 2014 due to colder than normal winter temperatures.

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

(Quarterly Average)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 36.45**	$ 40.88	$ 62.27
Pelican Lake heavy crude oil ($/bbl)	**$ 33.25**	$ 39.54	$ 62.33
Primary heavy crude oil ($/bbl)	**$ 31.14**	$ 39.97	$ 62.47
Bitumen (thermal oil) ($/bbl)	**$ 27.92**	$ 37.46	$ 58.64
Natural gas ($/Mcf)	**$ 2.73**	$ 2.99	$ 4.22

(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 39% to average $65.13 per bbl for the year ended December 31, 2015 from $106.63 per bbl for the year ended December 31, 2014. North Sea realized crude oil prices decreased 31% to average $57.50 per bbl for the fourth quarter of 2015 from $83.32 per bbl for the fourth quarter of 2014 and decreased 8% from $62.28 per bbl for the third quarter of 2015. 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 decrease in realized crude oil prices for the three months and year ended December 31, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 35% to average $63.13 per bbl for the year ended December 31, 2015 from $97.81 per bbl for the year ended December 31, 2014. Offshore Africa realized crude oil prices decreased 23% to average $53.37 per bbl for the fourth quarter of 2015 from $68.90 per bbl for the fourth quarter of 2014 and decreased 18% from $65.31 per bbl for the third quarter of 2015. 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 decrease in realized crude oil prices for months and year ended December 31, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, partially offset by the weaker Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 3.71**	$ 4.34	$ 9.76	**$ 4.57**	$ 13.74
North Sea	**$ 0.14**	$ 0.17	$ 0.17	**$ 0.14**	$ 0.33
Offshore Africa	**$ 2.61**	$ 2.89	$ 4.83	**$ 2.87**	$ 6.83
Company average	**$ 3.49**	$ 4.09	$ 9.05	**$ 4.30**	$ 12.99
Natural gas ($/Mcf) (1)					
North America	**$ 0.10**	$ 0.11	$ 0.23	**$ 0.09**	$ 0.36
Offshore Africa	**$ 0.44**	$ 0.41	$ 0.99	**$ 0.46**	$ 1.74
Company average	**$ 0.10**	$ 0.11	$ 0.24	**$ 0.10**	$ 0.38
Company average ($/BOE) (1)	**$ 2.38**	$ 2.81	$ 6.10	**$ 2.85**	$ 8.90

(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, 2015 and the comparable periods reflected movements in benchmark commodity prices and fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the year ended December 31, 2015 compared with 19% of product sales for the year ended December 31, 2014. Crude oil and NGLs royalties averaged approximately 13% of product sales for the fourth quarter of 2015 compared with 17% for the fourth quarter of 2014 and 12% for the third quarter of 2015. The decrease in royalties for the three months and year ended December 31, 2015 from the comparable periods in 2014 was primarily due to lower realized crude oil prices. The increase in crude oil and NGL royalty rates for the fourth quarter of 2015 from the third quarter of 2015 was due to lower expenditures for Oil Sands Royalty projects. North America crude oil and NGLs royalties per bbl are anticipated to average 7% to 9% of product sales for 2016.

Natural gas royalties averaged approximately 4% of product sales for the year ended December 31, 2015 compared with 8% of product sales for the year ended December 31, 2014. Natural gas royalties averaged approximately 4% of product sales for the fourth quarter of 2015 compared with 6% for the fourth quarter of 2014 and 4% for the third quarter of 2015. The decrease in natural gas royalty rates for the three months and year ended December 31, 2015 from the comparable periods in 2014 was due to lower realized natural gas prices. Natural gas royalty rates for the fourth quarter of 2015 were comparable with the third quarter of 2015. North America natural gas royalties are anticipated to average 1.5% to 2.5% of product sales for 2016.

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 5% for the year ended December 31, 2015 compared with 8% for the year ended December 31, 2014. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2015 compared with 7% for the fourth quarter of 2014 and 4% for the third quarter of 2015. The decrease in royalties for the three months and year ended December 31, 2015 from the comparable periods in 2014 was primarily a result of the timing of liftings from various fields and the status of payout in the various fields. Royalty rates in the fourth quarter of 2015 were comparable to the third quarter of 2015. Offshore Africa royalty rates are anticipated to average 6% to 8% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.45**	$ 11.64	$ 14.38	**$ 12.51**	$ 14.98
North Sea	**$ 56.97**	$ 72.69	$ 68.64	**$ 63.67**	$ 74.04
Offshore Africa	**$ 26.08**	$ 40.53	$ 50.54	**$ 33.32**	$ 43.97
Company average	**$ 14.26**	$ 15.70	$ 18.69	**$ 15.74**	$ 18.25
Natural gas ($/Mcf) (1)					
North America	**$ 1.17**	$ 1.25	$ 1.34	**$ 1.27**	$ 1.42
North Sea	**$ 3.27**	$ 3.85	$ 6.35	**$ 4.41**	$ 9.10
Offshore Africa	**$ 1.55**	$ 1.43	$ 3.35	**$ 1.76**	$ 3.22
Company average	**$ 1.22**	$ 1.31	$ 1.39	**$ 1.34**	$ 1.48
Company average ($/BOE) (1)	**$ 11.55**	$ 12.68	$ 14.66	**$ 12.70**	$ 14.67

(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, 2015 decreased 16% to $12.51 per bbl from $14.98 per bbl for the year ended December 31, 2014. North America crude oil and NGLs production expense for the fourth quarter of 2015 decreased 20% to $11.45 per bbl from $14.38 per bbl for the fourth quarter of 2014 and decreased 2% from $11.64 per bbl for the third quarter of 2015. The fourth quarter of 2015 reflected a continued reduction in production expense, as a result of the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America crude oil and NGLs production expense was within the Company's previously issued guidance of $12.25 to $13.25 per bbl and is anticipated to average $11.25 to $12.25 per bbl for 2016.

North America natural gas production expense for the year ended December 31, 2015 decreased 11% to $1.27 per Mcf from $1.42 per Mcf for the year ended December 31, 2014. North America natural gas production expense for the fourth quarter of 2015 decreased 13% to $1.17 per Mcf from $1.34 per Mcf for the fourth quarter of 2014 and decreased by 6% from $1.25 per Mcf for the third quarter of 2015. The fourth quarter of 2015 reflected a continued reduction in production expense, as a result of the Company's ongoing focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America natural gas production expense was within the Company's previously issued guidance of $1.25 to $1.35 per Mcf and is anticipated to average $1.10 to $1.30 per Mcf for 2016.

North Sea

North Sea crude oil production expense for the year ended December 31, 2015 decreased 14% to $63.67 per bbl from $74.04 per bbl for the year ended December 31, 2014. North Sea crude oil production expense for the fourth quarter of 2015 decreased 17% to $56.97 per bbl from $68.64 per bbl for the fourth quarter of 2014 and decreased 22% from $72.69 per bbl for the third quarter of 2015. The decrease in production expense for the three months and year ended December 31, 2015 from comparable periods was primarily due to higher production volumes on a relatively fixed cost structure and reflected the Company's continuous focus on cost control and efficiencies, partially offset by the impact of the weaker Canadian dollar from comparable periods and the impact of product inventory valuation adjustments. North Sea crude oil production expense was within the Company's previously issued guidance of $58.00 to $64.00 per bbl and is anticipated to average $47.00 to $53.00 per bbl for 2016, reflecting the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2015 decreased 24% to $33.32 per bbl from $43.97 per bbl for the year ended December 31, 2014. Offshore Africa crude oil production expense for the fourth quarter of 2015 averaged $26.08 per bbl, a decrease of 48% from $50.54 per bbl for the fourth quarter of 2014 and a decrease of 36% from $40.53 per bbl for the third quarter of 2015. The decrease in production expense for the three months and year ended December 31, 2015 from comparable periods in 2014 was primarily due to the impact of higher production volumes. The decrease in production expense for the fourth quarter compared with the third quarter of 2015 was primarily due to the timing of liftings from various fields, including the Olowi field, which have different cost structures, offset by the impact of the weaker Canadian dollar from comparable periods and the impact of product inventory valuation adjustments in Olowi. Annual 2015 Offshore Africa production expense exceeded the Company's previously issued guidance of $24.00 to $28.00 and is expected to average $18.00 to $22.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense ($ millions)	**$ 1,330**	$ 1,208	$ 1,210	**$ 4,909**	$ 4,275
$/BOE (1)	**$ 19.95**	$ 18.25	$ 17.76	**$ 18.50**	$ 17.27

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

The increase in depletion, depreciation and amortization expense for the three months and year ended December 31, 2015 from the comparable periods primarily reflected increased sales volumes in the international segments as well as depletion expense resulting from the Company's derecognition of exploration and evaluation assets in Block CI-514 in Côte, D'Ivoire, Offshore Africa.

Depletion, depreciation and amortization expense on a per barrel basis for the year ended December 31, 2015 increased 7% to $18.50 per BOE from $17.27 per BOE for the year ended December 31, 2014. Depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2015 increased 12% to $19.95 per BOE from $17.76 per BOE for the fourth quarter of 2014 and increased by 9% from $18.25 per BOE for the third quarter of 2015. The increase from the comparable periods reflected increased sales volumes in the International segments which have higher associated depletion rates, together with the impact of depletion expense related to Block CI-514 in Côte d'Ivoire, Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense ($ millions)	**$ 35**	$ 36	$ 37	**$ 142**	$ 146
$/BOE [(1)]	**$ 0.54**	$ 0.54	$ 0.56	**$ 0.54**	$ 0.59

(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 on a per barrel basis for the year ended December 31, 2015 decreased 8% to $0.54 per BOE from $0.59 per BOE for the year ended December 31, 2014. Asset retirement obligation accretion expense for the fourth quarter of 2015 decreased 4% to $0.54 per BOE from $0.56 per BOE for the fourth quarter of 2014 and was comparable with the third quarter of 2015.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the fourth quarter of 2015, operating performance continued to be strong, leading to average production of 129,050 bbl/d, reflecting high utilization rates and reliability.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
SCO sales price [(1)]	**$ 57.49**	$ 60.66	$ 79.23	**$ 61.39**	$ 100.27
Bitumen value for royalty purposes [(1) (2)]	**$ 24.37**	$ 33.20	$ 56.98	**$ 32.14**	$ 67.63
Bitumen royalties [(1) (3)]	**$ 0.99**	$ 1.32	$ 4.44	**$ 1.08**	$ 5.77
Transportation	**$ 1.66**	$ 1.82	$ 1.76	**$ 1.81**	$ 1.85

(1) Amounts expressed on a per unit basis are based on sales volumes.
(2) Calculated as the quarterly average of the bitumen valuation methodology price.
(3) Calculated based on actual bitumen royalties expensed during the period; divided by the corresponding SCO sales volumes.

Realized SCO sales prices averaged $61.39 per bbl for the year ended December 31, 2015, a decrease of 39% compared with $100.27 per bbl for the year ended December 31, 2014. Realized SCO sales prices averaged $57.49 per bbl for the fourth quarter of 2015, a decrease of 27% compared with $79.23 per bbl for the fourth quarter of 2014 and a decrease of 5% compared with $60.66 per bbl for the third quarter of 2015. The decrease in SCO pricing for the three months and year ended December 31, 2015 from the comparable periods was primarily due to movements in WTI benchmark pricing and the impact of industry wide 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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Cash production costs	**$ 344**	$ 321	$ 395	**$ 1,332**	$ 1,609
Less: costs incurred during turnaround periods	**–**	–	–	**(45)**	(98)
Adjusted cash production costs	**$ 344**	$ 321	$ 395	**$ 1,287**	$ 1,511
Adjusted cash production costs, excluding natural gas costs	**$ 326**	$ 300	$ 368	**$ 1,212**	$ 1,395
Adjusted natural gas costs	**18**	21	27	**75**	116
Adjusted cash production costs	**$ 344**	$ 321	$ 395	**$ 1,287**	$ 1,511

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Adjusted cash production costs, excluding natural gas costs	**$ 27.10**	$ 25.28	$ 31.97	**$ 26.95**	$ 34.33
Adjusted natural gas costs	**1.46**	1.76	2.37	**1.66**	2.85
Adjusted cash production costs	**$ 28.56**	$ 27.04	$ 34.34	**$ 28.61**	$ 37.18
Sales (bbl/d)	**130,990**	129,033	125,092	**123,231**	111,351

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

Adjusted cash production costs for the year ended December 31, 2015 decreased 23% to $28.61 per bbl from $37.18 per bbl for the year ended December 31, 2014. Adjusted cash production costs for the fourth quarter of 2015 averaged $28.56 per bbl, a decrease of 17% compared with $34.34 per bbl for the fourth quarter of 2014 and an increase of 6% compared with $27.04 per bbl for the third quarter of 2015. The decrease in adjusted cash production costs for the three months and year ended December 31, 2015 from the comparable periods in 2014 primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs, resulting in annual cash production costs being below the Company's previously issued guidance of $29.00 to $32.00 per bbl. The slight increase in adjusted cash production costs in the fourth quarter compared with the third quarter of 2015 reflected maintenance activities completed during the quarter. Cash production costs are anticipated to average $27.00 to $30.00 per bbl for 2016.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Depletion, depreciation and amortization	**$ 139**	$ 165	$ 194	**$ 562**	$ 596
Less: depreciation incurred during turnaround period	**–**	–	–	**(5)**	(28)
Adjusted depletion, depreciation and amortization	**$ 139**	$ 165	$ 194	**$ 557**	$ 568
$/bbl (1)	**$ 11.48**	$ 13.95	$ 16.85	**$ 12.37**	$ 13.97

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

The decrease in depletion, depreciation and amortization expense for the three months and year ended December 31, 2015 from the comparable periods in 2014 primarily reflected the impact of minor asset derecognitions in the comparable periods, partially offset by the impact of higher sales volumes in 2015.

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the year ended December 31, 2015 decreased 11% to $12.37 per bbl from $13.97 per bbl for the year ended December 31, 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the fourth quarter of 2015 decreased 32% to $11.48 per bbl from $16.85 per bbl for the fourth quarter of 2014 and decreased 18% from $13.95 per bbl for the third quarter of 2015. Depletion, depreciation and amortization expense on a per barrel basis decreased for the three months and year ended December 31, 2015 from comparable periods in 2014 primarily due to a lower depletion rate associated with the increase in productive capacity of the upgrader and related infrastructure. The decrease in fourth quarter depletion, depreciation and amortization expense on a per barrel basis compared with the third quarter reflects minor asset derecognitions in the third quarter.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense	**$ 8**	$ 8	$ 12	**$ 31**	$ 47
$/bbl (1)	**$ 0.64**	$ 0.65	$ 1.02	**$ 0.69**	$ 1.16

(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 on a per barrel basis for the year ended December 31, 2015 decreased 41% to $0.69 per bbl from $1.16 per bbl for the year ended December 31, 2014. Asset retirement obligation accretion expense for the fourth quarter of 2015 decreased 37% to $0.64 per bbl from $1.02 per bbl for the fourth quarter of 2014 and decreased 2% from $0.65 per bbl for the third quarter of 2015.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Revenue	**$ 33**	$ 33	$ 29	**$ 136**	$ 120
Production expense	**7**	7	7	**32**	34
Midstream cash flow	**26**	26	22	**104**	86
Depreciation	**3**	3	2	**12**	9
Equity loss from Redwater Partnership	**12**	20	5	**44**	8
Segment earnings before taxes	**$ 11**	$ 3	$ 15	**$ 48**	$ 69

Midstream operating results were consistent with the comparable periods.

The Company has a 50% interest in the North West Redwater Partnership (“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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). Subsequent to December 31, 2015, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, 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 first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. During the third quarter of 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044. As at December 31, 2015, Redwater Partnership had borrowings of $1,417 million under its secured $3,500 million syndicated credit facility. Subsequent to December 31, 2015, the 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.

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

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense	**$ 93**	$ 93	$ 100	**$ 390**	$ 367
$/BOE (1)	**$ 1.18**	$ 1.20	$ 1.26	**$ 1.26**	$ 1.28

(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, 2015 decreased 2% to $1.26 per BOE from $1.28 per BOE for the year ended December 31, 2014. Administration expense for the fourth quarter of 2015 decreased 6% to $1.18 per BOE from $1.26 per BOE for the fourth quarter of 2014 and decreased 2% from $1.20 per BOE for the third quarter of 2015. Administration expense per BOE decreased from the comparable periods primarily due to lower staffing related costs and general corporate costs, partially offset by the impact of lower recoveries due to the reduction in the capital expenditure program.

SHARE-BASED COMPENSATION

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense (recovery)	**$ 56**	$ (87)	$ (144)	**$ (46)**	$ 66

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 $46 million share-based compensation recovery for the year ended December 31, 2015, 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, 2015, the Company recovered $10 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (December 31, 2014 – $14 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended			Year Ended	
	Dec 31 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Expense, gross	**$ 133**	$ 142	$ 141	**$ 566**	$ 527
Less: capitalized interest	**60**	64	57	**244**	204
Expense, net	**$ 73**	$ 78	$ 84	**$ 322**	$ 323
$/BOE (1)	**$ 0.93**	$ 1.00	$ 1.05	**$ 1.04**	$ 1.12
Average effective interest rate	**3.8%**	3.8%	4.0%	**3.9%**	3.9%

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

Gross interest and other financing expenses for the year ended December 31, 2015 increased from 2014 primarily due to higher overall debt levels. Gross interest and other financing expense for the three months ended December 31, 2015 decreased from the comparable periods primarily due to interest on PRT recoveries in the North Sea, partially offset by the impact of higher overall debt levels. Capitalized interest of $244 million for the year ended December 31, 2015 was primarily related to the Horizon Phase 2/3 expansion.

Net interest and other financing expense on a per BOE basis for the year ended December 31, 2015 decreased 7% to $1.04 per BOE from $1.12 per BOE for 2014. Net interest and other financing expense on a per barrel basis for the fourth quarter of 2015 decreased 11% to $0.93 per BOE from $1.05 per BOE for the fourth quarter of 2014 and decreased 7% from $1.00 per BOE for the third quarter of 2015. The decrease for the year ended December 31, 2015 was primarily due to higher sales volumes. The decrease for the three months ended December 31, 2015 from the comparable periods was primarily due to interest on PRT recoveries in the North Sea, partially offset by higher overall debt levels.

The Company's average effective interest rate for the three months and year ended December 31, 2015 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

The Company periodically 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 2015	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Crude oil and NGLs financial instruments	**$ (218)**	$ (173)	$ (284)	**$ (599)**	$ (284)
Natural gas financial instruments	**–**	–	1	**–**	34
Foreign currency contracts	**(37)**	(90)	(52)	**(244)**	(99)
Realized gain	**(255)**	(263)	(335)	**(843)**	(349)
Crude oil and NGLs financial instruments	**189**	(12)	(403)	**394**	(427)
Natural gas financial instruments	**–**	–	(3)	**–**	(3)
Foreign currency contracts	**(15)**	(17)	2	**(20)**	(21)
Unrealized loss (gain)	**174**	(29)	(404)	**374**	(451)
Net gain	**$ (81)**	$ (292)	$ (739)	**$ (469)**	$ (800)

During the year ended December 31, 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company recorded a net unrealized loss of $374 million ($275 million after-tax) on its risk management activities for the year ended December 31, 2015, including an unrealized loss of $174 million ($128 million after-tax) for the fourth quarter of 2015 (September 30, 2015 – unrealized gain of $29 million; $24 million after-tax; December 31, 2014 – unrealized gain of $404 million; $303 million after-tax), primarily related to changes in the fair value of these contracts.

Complete details related to outstanding derivative financial instruments at December 31, 2015 are disclosed in note 14 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Net realized (gain) loss	**$ (5)**	$ (28)	$ 18	**$ (97)**	$ 47
Net unrealized loss [1]	**170**	351	106	**858**	256
Net loss	**$ 165**	$ 323	$ 124	**$ 761**	$ 303

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

The net realized foreign exchange gain for the year ended December 31, 2015 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 loss for the year ended December 31, 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2015 – unrealized gain of $129 million, September 30, 2015 – unrealized gain of $267 million, December 31, 2014 – unrealized gain of $115 million; year ended December 31, 2015 – unrealized gain of $649 million, December 31, 2014 – unrealized gain of $259 million). The US/Canadian dollar exchange rate at December 31, 2015 was US$0.7225 (September 30, 2015 – US$0.7466, December 31, 2014 – US$0.8620).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Dec 31 2015**	 Sep 30 2015	 Dec 31 2014	Year Ended **Dec 31 2015**	 Dec 31 2014
North America [1]	**$ (66)**	$ 65	$ 123	**$ 86**	$ 702
North Sea	**(18)**	(16)	(23)	**(117)**	(68)
Offshore Africa	**5**	5	8	**17**	43
PRT recovery – North Sea	**(71)**	(61)	(86)	**(258)**	(273)
Other taxes	**2**	2	5	**11**	23
Current income tax (recovery) expense	**(148)**	(5)	27	**(261)**	427
Deferred income tax expense	**(1)**	8	254	**216**	681
Deferred PRT (recovery) expense – North Sea	**(32)**	10	(1)	**15**	126
Deferred income tax (recovery) expense	**(33)**	18	253	**231**	807
	$ (181)	$ 13	$ 280	**$ (30)**	$ 1,234
Income tax rate and other legislative changes [2] [3]	**–**	–	–	**(351)**	–
	$ (181)	$ 13	$ 280	**$ (381)**	$ 1,234
Effective income tax rate on adjusted net earnings from operations [4]	**59%**	28%	26%	**61%**	25%

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

(2) 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. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $579 million.

(3) During the first quarter of 2015, the UK government enacted tax rate reductions to the supplementary charge on oil and gas profits and the Petroleum Revenue Tax ("PRT"), and replaced the Brownfield Allowance with a new Investment Allowance, resulting in a decrease in the Company's deferred income tax liability of $228 million.

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

The current PRT recovery in the North Sea in the three months and year ended December 31, 2015 and the comparative quarters included the impact of abandonment expenditures on the Murchison platform.

The effective income tax rate for the three months and year ended December 31, 2015 included the impact of non-taxable items in North America and the North Sea as well as 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 June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $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 are 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 income tax changes, the Company's deferred 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 2016, based on forward commodity prices and the current availability of tax pools, the Company expects to incur current income tax recoveries of $260 million to $320 million in Canada and recoveries of $250 million to $300 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Dec 31 2015**	Three Months Ended Sep 30 2015	Three Months Ended Dec 31 2014	Year Ended **Dec 31 2015**	Year Ended Dec 31 2014
Exploration and Evaluation					
Net (proceeds) expenditures [2] [3] [6]	**$ (885)**	$ 5	$ 97	**$ (805)**	$ 1,190
Property, Plant and Equipment					
Net property (disposals) acquisitions [2] [3] [6]	**(443)**	(70)	72	**(451)**	2,893
Well drilling, completion and equipping	**237**	237	582	**965**	2,162
Production and related facilities	**154**	191	482	**908**	1,830
Capitalized interest and other [4]	**26**	23	28	**102**	106
Net (proceeds) expenditures	**(26)**	381	1,164	**1,524**	6,991
Total Exploration and Production	**(911)**	386	1,261	**719**	8,181
Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**578**	668	739	**2,187**	2,502
Sustaining capital	**55**	64	83	**301**	352
Turnaround costs	**5**	3	8	**18**	29
Capitalized interest and other [4]	**68**	42	32	**224**	227
Total Oil Sands Mining and Upgrading	**706**	777	862	**2,730**	3,110
Midstream	**2**	2	(16)	**8**	62
Abandonments [5]	**105**	65	101	**370**	346
Head office	**2**	10	12	**26**	45
Total net capital (proceeds) expenditures	**$ (96)**	$ 1,240	$ 2,220	**$ 3,853**	$ 11,744
By segment					
North America [2] [3] [6]	**$ (1,126)**	$ 199	$ 1,029	**$ (119)**	$ 7,500
North Sea	**34**	41	105	**230**	400
Offshore Africa	**181**	146	127	**608**	281
Oil Sands Mining and Upgrading	**706**	777	862	**2,730**	3,110
Midstream	**2**	2	(16)	**8**	62
Abandonments [5]	**105**	65	101	**370**	346
Head office	**2**	10	12	**26**	45
Total	**$ (96)**	$ 1,240	$ 2,220	**$ 3,853**	$ 11,744

(1) Net capital expenditures exclude adjustments related to differences between carrying amounts and tax values, and other fair value adjustments.
(2) Includes Business Combinations.
(3) Includes proceeds from the Company's dispositions of properties.
(4) Capitalized interest and other includes expenditures related to land acquisition and retention, seismic, and other adjustments.
(5) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table.
(6) The above noted figures include non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets in the fourth quarter of 2015 and the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in the third quarter of 2015.

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 managing 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 2015 were $3,853 million compared with $11,744 million for 2014. Capital expenditures for 2015 reflected the Company's previously announced reduction in its capital program by $3,165 million for the year, as well as changes to its capital allocation strategy, including the decrease in drilling activity in North America, partially offset by the planned drilling activities in Offshore Africa. Capital expenditures for 2015 also reflected the disposition of a number of North America royalty assets on December 16, 2015, including exploration and evaluation assets of $488 million and property, plant and equipment of $480 million, for total consideration of $1,658 million. Total consideration on the disposition was comprised of $673 million in cash, together with $985 million of non-cash share consideration of approximately 44.4 million common shares of PrairieSky Royalty Ltd.

As at December 31, 2015, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

Drilling Activity

	Three Months Ended			Year Ended	
(number of wells)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Net successful natural gas wells	**4**	4	16	**19**	75
Net successful crude oil wells (1)	**2**	66	325	**115**	1,023
Dry wells	**–**	4	8	**6**	19
Stratigraphic test / service wells	**73**	1	74	**166**	437
Total	**79**	75	423	**306**	1,554
Success rate (excluding stratigraphic test / service wells)	**100%**	95%	98%	**96%**	98%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 1% of the total net capital expenditures for the year ended December 31, 2015 compared with approximately 66% for the year ended December 31, 2014.

During the fourth quarter of 2015, the Company targeted 4 net natural gas wells in Northwest Alberta. The Company also targeted 1 net primary heavy crude oil well in the Company's Northern Plains region.

Overall thermal oil production for the fourth quarter of 2015 averaged approximately 135,100 bbl/d compared with approximately 119,000 bbl/d for the fourth quarter of 2014 and approximately 133,200 bbl/d for the third quarter of 2015. Production volumes in the fourth quarter of 2015 reflected the cyclic nature of thermal oil production at Primrose and production at Kirby South.

Operating performance at the Pelican Lake tertiary recovery project continued to be strong, leading to average production of approximately 50,800 bbl/d in 2015 (2014 – 50,100 bbl/d).

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the fourth quarter of 2015 continued to focus on field construction of the hydrogen unit, hydrotreater unit, vacuum distillation unit and distillation recovery unit, tank farms, tailings re-handling plant, froth treatment, froth tank, tailings transfer pumphouses and pipelines, extraction plant, ore preparation plants, and superpot along with engineering, procurement and construction related to tailings retrofit, sour water concentrator, combined hydrotreater and sulphur recovery units**.** In addition, the new Extraction trains 3 and 4 were commissioned during the fourth quarter of 2015. The Company targets to complete Phase 2B in 2016.

North Sea

During 2015, the Company completed one injection well and no further drilling activities are currently planned for 2016. The decommissioning activities at the Murchison platform are ongoing and are expected to continue for approximately five years.

Offshore Africa

During 2015, at the Espoir field, Côte d'Ivoire, the Company drilled 5 gross producing wells and 1 injector well, adding net production volumes of approximately 6,900 bbl/d to date. In 2016, upon completion of the sixth gross producing well, no additional wells will be drilled in the program. The infill drilling program is currently tracking to below its original sanction costs and above original sanction production.

During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 5 gross wells, adding net production volumes of approximately 13,400 bbl/d to date. In late December, the Baobab field was temporarily shut-in due to a riser failure, delaying first oil on the fifth gross well. After inspection of the riser system, production was reinstated in late January 2016. In 2016, upon completion of the sixth gross well, no additional wells will be drilled in the program. The drilling program is currently tracking to below its original sanction costs and above original sanction production.

During the fourth quarter of 2015, the Company provided notice of its withdrawal from Block CI-514 in Côte d'Ivoire, Offshore Africa.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2015**	Sep 30 2015	Dec 31 2014
Working capital (deficit) (1)	**$ 1,193**	$ 309	$ (673)
Long-term debt (2) (3)	**$ 16,794**	$ 16,510	$ 14,002
Share capital	**$ 4,541**	$ 4,533	$ 4,432
Retained earnings	**22,765**	22,885	24,408
Accumulated other comprehensive income	**75**	67	51
Shareholders' equity	**$ 27,381**	$ 27,485	$ 28,891
Debt to book capitalization (3) (4)	**38%**	38%	33%
Debt to market capitalization (3) (5)	**34%**	37%	26%
After-tax return on average common shareholders' equity (6)	**(2%)**	2%	14%
After-tax return on average capital employed (3) (7)	**(1%)**	2%	10%

(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, 2015, the Company's capital resources consisted primarily of cash flow from operations, available bank credit facilities and access to debt capital markets. Cash 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, 2014. 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 cash flow from operations, the flexibility of its capital expenditure programs supported by its 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 cash 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 decline in commodity prices, 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 fourth quarter of 2015, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States until November 2017. If issued, these securities may be offered separately or together, in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
    - During the second quarter of 2015, the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes. In addition, the $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. As a result, the Company's available liquidity increased by $350 million;
    - 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 2015, the Company extended its existing $1,000 million non-revolving term credit facility to January 2017. In addition, the Company entered into a new $1,500 million non-revolving term credit facility maturing April 2018. Both facilities were fully drawn at December 31, 2015. Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings outstanding under the $1,000 million non-revolving term credit facility and extended the facility to February 2019 from January 2017. Subsequent to December 31, 2015, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. Borrowings under this new facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans;
    - Subsequent to December 31, 2015, the Company retained its investment grade ratings with both Standard & Poor's Rating Services and DBRS Limited. In addition, Moody's Investors Service, Inc. downgraded the Company's credit ratings within the investment grade debt rating scale. The current changes in the Company's credit ratings are not expected to have a significant impact on the Company's access to debt capital markets, its US commercial paper program or on its overall cost of borrowing.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. Beginning in 2015, all of the Company's credit facilities are now subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0; 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 second quarter of 2015, the Company repaid $400 million of 4.95% medium term notes.

At December 31, 2015, the Company had in place bank credit facilities of $7,481 million, of which approximately $3,495 million, net of commercial paper issuances of $692 million, was available for general corporate purposes.

At December 31, 2015, the Company had long-term debt with a carrying amount of $1,037 million maturing over the next 12 months (US$500 million of debt securities at three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% debt securities due August 2016). These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.

At December 31, 2015, the Company had total US dollar denominated debt with a carrying amount of $11,981 million (US$8,657 million). This included $5,615 million (US$4,057 million) hedged by way of cross currency swaps (US$2,900 million) and foreign currency forwards (US$1,157 million). The fixed repayment amount of these hedging instruments is $4,845 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $770 million to $11,211 million as at December 31, 2015.

Long-term debt was $16,794 million at December 31, 2015, resulting in a debt to book capitalization ratio of 38% (December 31, 2014 – 33%); 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 cash 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, 2015 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 March 2, 2016 the Company had no commodity derivative financial instruments outstanding.

Share Capital

As at December 31, 2015, there were 1,094,668,000 common shares outstanding (December 31, 2014 – 1,091,837,000 common shares) and 74,615,000 stock options outstanding. As at March 1, 2016, the Company had 1,094,704,000 common shares outstanding and 71,353,000 stock options outstanding.

On March 2, 2016, the Board of Directors declared a regular quarterly dividend at $0.23 per common share. On an annualized basis, the dividend of $0.92 per common share remains unchanged from the previous annual dividend rate. This reflects confidence in the Company's cash flow and provides a return to shareholders. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

In April 2015, the Company announced a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the year ended December 31, 2015, the Company did not purchase any common shares for cancellation.

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, 2015:

($ millions)	2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 423	$ 341	$ 303	$ 261	$ 246	$ 1,304
Offshore equipment operating leases and offshore drilling	$ 247	$ 93	$ 71	$ 22	$ –	$ –
Long-term debt (1) (2)	$ 1,730	$ 2,522	$ 2,899	$ 1,353	$ 1,427	$ 6,935
Interest and other financing expense (3)	$ 649	$ 564	$ 478	$ 437	$ 408	$ 4,608
Office leases	$ 42	$ 42	$ 42	$ 43	$ 42	$ 193
Other	$ 141	$ 38	$ 48	$ 1	$ –	$ –

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

(2) At December 31, 2015, the Company had US$500 million of debt securities at three-month LIBOR plus 0.375% due March 2016 and US$250 million of 6.00% debt securities due August 2016. These debt securities have been hedged by way of cross currency swaps with principal repayment amounts fixed at $555 million and $279 million respectively.

(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, 2015.

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.

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, 2014 and the unaudited interim financial statements for the three months and year ended December 31, 2015.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgments 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 critical accounting estimates is contained in the MD&A and the audited consolidated financial statements for the year ended December 31, 2014.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Dec 31 2015**	Dec 31 2014
ASSETS			
Current assets			
Cash and cash equivalents		**$ 69**	$ 25
Accounts receivable		**1,277**	1,889
Current income taxes		**677**	228
Inventory		**525**	665
Prepaids and other		**162**	172
Investment in PrairieSky Royalty Ltd.	5	**974**	–
Current portion of other long-term assets	6	**375**	510
		4,059	3,489
Exploration and evaluation assets	3	**2,586**	3,557
Property, plant and equipment	4	**51,475**	52,480
Other long-term assets	6	**1,155**	674
		$ 59,275	$ 60,200
LIABILITIES			
Current liabilities			
Accounts payable		**$ 571**	$ 564
Accrued liabilities		**2,089**	3,279
Current portion of long-term debt	7	**1,729**	980
Current portion of other long-term liabilities	8	**206**	319
		4,595	5,142
Long-term debt	7	**15,065**	13,022
Other long-term liabilities	8	**2,890**	4,175
Deferred income taxes		**9,344**	8,970
		31,894	31,309
SHAREHOLDERS' EQUITY			
Share capital	10	**4,541**	4,432
Retained earnings		**22,765**	24,408
Accumulated other comprehensive income	11	**75**	51
		27,381	28,891
		$ 59,275	$ 60,200

Commitments and contingencies (note 15).

Approved by the Board of Directors on March 2, 2016

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Dec 31 2015**	Three Months Ended Dec 31 2014	Year Ended **Dec 31 2015**	Year Ended Dec 31 2014
Product sales		**$ 2,963**	$ 4,850	**$ 13,167**	$ 21,301
Less: royalties		**(170)**	(466)	**(804)**	(2,438)
Revenue		**2,793**	4,384	**12,363**	18,863
Expenses					
Production		**1,119**	1,399	**4,726**	5,265
Transportation and blending		**575**	759	**2,379**	3,232
Depletion, depreciation and amortization	3, 4	**1,472**	1,406	**5,483**	4,880
Administration		**93**	100	**390**	367
Share-based compensation	8	**56**	(144)	**(46)**	66
Asset retirement obligation accretion	8	**43**	49	**173**	193
Interest and other financing expense		**73**	84	**322**	323
Risk management activities	14	**(81)**	(739)	**(469)**	(800)
Foreign exchange loss		**165**	124	**761**	303
Gains on disposition of properties and corporate acquisitions	4	**(690)**	(137)	**(739)**	(137)
Loss from investments	5, 6	**18**	5	**50**	8
		2,843	2,906	**13,030**	13,700
Earnings (loss) before taxes		**(50)**	1,478	**(667)**	5,163
Current income tax (recovery) expense	9	**(148)**	27	**(261)**	427
Deferred income tax (recovery) expense	9	**(33)**	253	**231**	807
Net earnings (loss)		**$ 131**	$ 1,198	**$ (637)**	$ 3,929
Net earnings (loss) per common share					
Basic	13	**$ 0.12**	$ 1.10	**$ (0.58)**	$ 3.60
Diluted	13	**$ 0.12**	$ 1.09	**$ (0.58)**	$ 3.58

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2015**	Three Months Ended Dec 31 2014	Year Ended **Dec 31 2015**	Year Ended Dec 31 2014
Net earnings (loss)	**$ 131**	$ 1,198	**$ (637)**	$ 3,929
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2014 – $nil) – three months ended; $2 million (2014 – $nil) – year ended	**(15)**	6	**(23)**	5
Reclassification to net earnings (loss), net of taxes of $1 million (2014 – $nil) – three months ended; $2 million (2014 – $1 million) – year ended	**(2)**	1	**(13)**	8
	(17)	7	**(36)**	13
Foreign currency translation adjustment				
Translation of net investment	**25**	(3)	**60**	(4)
Other comprehensive income, net of taxes	**8**	4	**24**	9
Comprehensive income (loss)	**$ 139**	$ 1,202	**$ (613)**	$ 3,938

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended **Dec 31 2015**	Dec 31 2014
Share capital	10		
Balance – beginning of year		**$ 4,432**	$ 3,854
Issued upon exercise of stock options		**91**	488
Previously recognized liability on stock options exercised for common shares		**18**	129
Purchase of common shares under Normal Course Issuer Bid		**–**	(39)
Balance – end of year		**4,541**	4,432
Retained earnings			
Balance – beginning of year		**24,408**	21,876
Net earnings (loss)		**(637)**	3,929
Purchase of common shares under Normal Course Issuer Bid	10	**–**	(414)
Dividends on common shares	10	**(1,006)**	(983)
Balance – end of year		**22,765**	24,408
Accumulated other comprehensive income	11		
Balance – beginning of year		**51**	42
Other comprehensive income, net of taxes		**24**	9
Balance – end of year		**75**	51
Shareholders' equity		**$ 27,381**	$ 28,891

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2015	Three Months Ended Dec 31 2014	Year Ended Dec 31 2015	Year Ended Dec 31 2014
Operating activities					
Net earnings (loss)		**$ 131**	$ 1,198	**$ (637)**	$ 3,929
Non-cash items					
Depletion, depreciation and amortization		**1,472**	1,406	**5,483**	4,880
Share-based compensation		**56**	(144)	**(46)**	66
Asset retirement obligation accretion		**43**	49	**173**	193
Unrealized risk management loss (gain)		**174**	(404)	**374**	(451)
Unrealized foreign exchange loss		**170**	106	**858**	256
Realized foreign exchange loss on repayment of US dollar debt securities		**–**	36	**–**	36
Loss from investments	5, 6	**23**	5	**55**	8
Deferred income tax (recovery) expense		**(33)**	253	**231**	807
Gains on disposition of properties and corporate acquisitions		**(690)**	(137)	**(739)**	(137)
Current income tax on disposition of properties		**33**	–	**33**	–
Other		**(103)**	(107)	**(22)**	(38)
Abandonment expenditures		**(105)**	(101)	**(370)**	(346)
Net change in non-cash working capital		**314**	158	**239**	(744)
		1,485	2,318	**5,632**	8,459
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net		**(73)**	(362)	**970**	1,195
Issue of medium-term notes, net	7	**–**	–	**107**	992
Issue of US dollar debt securities, net		**–**	382	**–**	1,482
Issue of common shares on exercise of stock options		**7**	40	**91**	488
Purchase of common shares under Normal Course Issuer Bid		**–**	(49)	**–**	(453)
Dividends on common shares		**(503)**	(246)	**(1,251)**	(955)
Net change in non-cash working capital		**–**	(6)	**(40)**	(22)
		(569)	(241)	**(123)**	2,727
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets (1)		**316**	(97)	**236**	(1,190)
Net expenditures on property, plant and equipment (1)		**(1,100)**	(2,022)	**(4,704)**	(10,208)
Current income tax on disposition of properties		**(33)**	–	**(33)**	–
Investment in other long-term assets		**–**	–	**(112)**	(113)
Net change in non-cash working capital		**(60)**	51	**(852)**	334
		(877)	(2,068)	**(5,465)**	(11,177)
Increase in cash and cash equivalents		**39**	9	**44**	9
Cash and cash equivalents – beginning of period		**30**	16	**25**	16
Cash and cash equivalents – end of period		**$ 69**	$ 25	**$ 69**	$ 25
Interest paid, net		**$ 94**	$ 134	**$ 541**	$ 521
Income taxes (received) paid		**$ (94)**	$ 127	**$ 42**	$ 792

(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.

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, 2014. 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, 2014.

2. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In May 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers" to provide guidance on the recognition of revenue and cash flows arising from an entity's contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements. In 2015, the IASB deferred the effective date for the new standard to January 1, 2018. The new standard is required to be adopted retrospectively, with earlier adoption permitted. The Company is assessing the impact of IFRS 15 on its consolidated financial statements.

In May 2014, the IASB issued an 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. This amendment is effective January 1, 2016 and is to be applied prospectively. Adoption of this amended standard is not expected to result in a significant impact to the Company's consolidated financial statements.

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The amendments are effective January 1, 2018. The Company is assessing the impact of this amendment on its consolidated financial statements.

Subsequent to December 31, 2015, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees. The new standard is effective January 1, 2019 with earlier adoption permitted providing that IFRS 15 has been adopted. The new standard is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company is assessing the impact of this standard on its 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, 2014	$ 3,426	$ –	$ 131	$ –	$ 3,557
Additions	**132**	**–**	**35**	**–**	**167**
Transfers to property, plant and equipment	**(567)**	**–**	**–**	**–**	**(567)**
Disposals/derecognitions [1]	**(491)**		**(96)**		**(587)**
Foreign exchange adjustments	**–**	**–**	**16**	**–**	**16**
At December 31, 2015	**$ 2,500**	**$ –**	**$ 86**	**$ –**	**$ 2,586**

(1) Refer to note 4 regarding the disposition of exploration and evaluation assets in the North America segment.

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 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, 2014	$ 60,606	$ 6,182	$ 3,858	$ 21,948	$ 570	$ 352	$ 93,516
Additions	**691**	**13**	**524**	**2,523**	**7**	**26**	**3,784**
Transfers from E&E assets	**567**	**–**	**–**	**–**	**–**	**–**	**567**
Disposals/derecognitions	**(1,324)**	**–**	**–**	**(128)**	**–**	**–**	**(1,452)**
Foreign exchange adjustments and other	**–**	**1,219**	**791**	**–**	**–**	**–**	**2,010**
At December 31, 2015	**$ 60,540**	**$ 7,414**	**$ 5,173**	**$ 24,343**	**$ 577**	**$ 378**	**$ 98,425**
Accumulated depletion and depreciation							
At December 31, 2014	$ 31,886	$ 4,049	$ 2,890	$ 1,864	$ 120	$ 227	$ 41,036
Expense	**4,226**	**383**	**177**	**562**	**12**	**27**	**5,387**
Disposals/derecognitions	**(758)**	**–**	**–**	**(128)**	**–**	**–**	**(886)**
Foreign exchange adjustments and other	**(7)**	**832**	**592**	**(4)**	**–**	**–**	**1,413**
At December 31, 2015	**$ 35,347**	**$ 5,264**	**$ 3,659**	**$ 2,294**	**$ 132**	**$ 254**	**$ 46,950**
Net book value							
– at December 31, 2015	**$ 25,193**	**$ 2,150**	**$ 1,514**	**$ 22,049**	**$ 445**	**$ 124**	**$ 51,475**
– at December 31, 2014	$ 28,720	$ 2,133	$ 968	$ 20,084	$ 450	$ 125	$ 52,480

Project costs not subject to depletion and depreciation	**Dec 31 2015**	Dec 31 2014
Horizon	**$ 6,017**	$ 5,492
Kirby Thermal Oil Sands – North	**$ 816**	$ 681

During the year ended December 31, 2015, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, including exploration and evaluation assets of $37 million, for net cash consideration of $406 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 $133 million. No net deferred income liabilities or pre-tax gains were recognized on these acquisitions.

On December 16, 2015, the Company disposed of a number of North America royalty income assets, including exploration and evaluation assets of $488 million and property, plant and equipment of $480 million, for total consideration of $1,658 million, resulting in a pre-tax gain on sale of properties of $690 million. Total consideration on the disposition was comprised of $673 million in cash, together with $985 million of non-cash share consideration of approximately 44.4 million common shares of PrairieSky Royalty Ltd. (“PrairieSky”) with a value of $22.16 per common share, determined as of the closing date. The cash consideration received on the disposition is an estimate, and may be subject to change based on the receipt of new information.

In addition, during 2015 the Company disposed of a number of North America crude oil and natural gas properties, including exploration and evaluation assets of $3 million and property, plant and equipment of $86 million, for total cash consideration of $134 million, together with associated asset retirement obligations of $4 million, resulting in a pre-tax gain on sale of properties of $49 million.

As at December 31, 2015, the Company assessed the recoverability of its property, plant and equipment and its exploration and evaluation assets, and determined the carrying amounts to be recoverable.

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, 2015, pre-tax interest of $244 million (December 31, 2014 – $204 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (December 31, 2014 – 3.9%).

5. INVESTMENT IN PRAIRIESKY ROYALTY LTD.

On December 16, 2015, as partial consideration for the disposal of a number of crude oil and natural gas royalty income assets, the Company received non-cash share consideration of $985 million, comprised of approximately 44.4 million common shares of PrairieSky at $22.16 per common share determined as of the closing date (refer to Note 4). PrairieSky is in the business of acquiring and managing oil and gas royalty income assets through indirect third-party oil and gas development. As the Company's investment constitutes less than 20% of the outstanding shares of PrairieSky, the investment is accounted for at fair value through profit or loss and is remeasured at each reporting date. As at December 31, 2015, the Company's investment in PrairieSky of $974 million has been classified as a current asset.

Subject to certain conditions, including applicable regulatory and/or Shareholder approvals, the Company has agreed with PrairieSky that, by no later than December 31, 2016, it will distribute sufficient common shares of PrairieSky to the Company's shareholders so that the Company, after such distribution, will hold less than 10% of the issued and outstanding common shares of PrairieSky.

The loss from investment related to PrairieSky was comprised as follows:

	Three Months Ended		Year Ended	
	Dec 31 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Fair value loss from PrairieSky	**$ 11**	$ –	**$ 11**	$ –
Dividend income from PrairieSky	**(5)**	–	**(5)**	–
	$ 6	$ –	**$ 6**	$ –

6. OTHER LONG-TERM ASSETS

	Dec 31 2015	Dec 31 2014
Investment in North West Redwater Partnership	**$ 254**	$ 298
North West Redwater Partnership subordinated debt (1)	**254**	120
Risk Management (note 14)	**854**	599
Other	**168**	167
	1,530	1,184
Less: current portion	**375**	510
	$ 1,155	$ 674

(1) Includes accrued interest.

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, each committed to provide funding up to $350 million by January 2016 in the form of subordinated debt bearing interest at prime plus 6%. During 2015, the Company and APMC each provided $112 million of subordinated debt (year ended December 31, 2014 – $113 million). Subsequent to December 31, 2015, the Company and APMC each provided an additional $99 million in subordinated debt. Should final Project costs exceed the revised cost estimate, the Company and APMC have agreed, 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 first quarter of 2015, Redwater Partnership issued $500 million of 2.10% series C senior secured bonds due February 2022 and $500 million of 3.70% series D senior secured bonds due February 2043. During the third quarter of 2015, Redwater Partnership issued $500 million of 3.20% series E senior secured bonds due April 2026 and $300 million of senior secured bonds through the reopening of its previously issued 4.05% series B senior secured bonds due July 2044. As at December 31, 2015, Redwater Partnership had additional borrowings of $1,417 million under its secured $3,500 million syndicated credit facility. Subsequent to December 31, 2015, 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.

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, 2015, the Company recognized an equity loss from Redwater Partnership of $12 million (year ended December 31, 2015 – $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 2015	Dec 31 2014
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 2,385**	$ 2,404
Medium-term notes	**2,500**	2,400
	4,885	4,804
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2015 – US$657 million; December 31, 2014 – $nil)	**909**	–
Commercial paper (US$500 million)	**692**	580
US dollar debt securities (US$7,500 million)	**10,380**	8,701
	11,981	9,281
Long-term debt before transaction costs and original issue discounts, net	**16,866**	14,085
Less: original issue discounts, net (1)	**(10)**	(21)
transaction costs (1) (2)	**(62)**	(62)
	16,794	14,002
Less: current portion of commercial paper	**692**	580
current portion of long-term debt (1) (2)	**1,037**	400
	$ 15,065	$ 13,022

(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, 2015, the Company had in place bank credit facilities of $7,481 million available for general corporate purposes, comprised of:

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing January 2017;
- a $1,500 million non-revolving term credit facility maturing April 2018;
- 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.

During the second quarter of 2015, the previously existing $1,500 million revolving syndicated credit facility was increased to $2,425 million and the maturity date was extended to June 2019 from June 2016. The previously existing $3,000 million revolving syndicated credit facility was reduced to $2,425 million and the maturity date was extended to June 2020 from June 2017. 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.

Borrowings under the $1,000 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans. As at December 31, 2015, the $1,000 million facility was fully drawn. Subsequent to December 31, 2015, the Company prepaid $250 million of the borrowings then outstanding and extended the facility to February 2019 from January 2017. Subsequent to December 31, 2015, the Company also entered into a new $125 million non-revolving term credit facility maturing February 2019, which was fully drawn. 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 term 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, 2015, the $1,500 million facility was fully drawn.

All of the Company's credit facilities are subject to a financial covenant that the Consolidated Debt to Capitalization Ratio, as defined in the credit agreements, shall not be more than 0.65 to 1.0.

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, 2015 was 1.7% (December 31, 2014 – 2.2%), and on long-term debt outstanding for the year ended December 31, 2015 was 3.9% (December 31, 2014 – 3.9%).

At December 31, 2015 letters of credit and guarantees aggregating $335 million, including a $39 million financial guarantee related to Horizon and $175 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 second quarter of 2015 the Company issued $500 million of series 2 medium-term notes, due August 2020, through the reopening of its previously issued 2.89% notes under a previous base shelf prospectus and repaid $400 million of 4.95% medium-term 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 $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

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 2015		Dec 31 2014
Asset retirement obligations	**$**	**2,950**	$	4,221
Share-based compensation		**128**		203
Other		**18**		70
		3,096		4,494
Less: current portion		**206**		319
	$	**2,890**	$	4,175

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 5.9% (December 31, 2014 – 4.6%). A reconciliation of the discounted asset retirement obligations was as follows:

		Dec 31 2015		Dec 31 2014
Balance – beginning of year	**$**	**4,221**	$	4,162
Liabilities incurred		**7**		41
Liabilities acquired, net		**129**		404
Liabilities settled		**(370)**		(346)
Asset retirement obligation accretion		**173**		193
Revision of cost, inflation rates and timing estimates		**(313)**		(907)
Change in discount rate		**(1,150)**		558
Foreign exchange adjustments		**253**		116
Balance – end of year		**2,950**		4,221
Less: current portion		**101**		121
	$	**2,849**	$	4,100

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 2015		Dec 31 2014
Balance – beginning of year	**$**	**203**	$	260
Share-based compensation (recovery) expense		**(46)**		66
Cash payment for stock options surrendered		**(1)**		(8)
Transferred to common shares		**(18)**		(129)
(Recovered from) capitalized to Oil Sands Mining and Upgrading		**(10)**		14
Balance – end of year		**128**		203
Less: current portion		**105**		158
	$	**23**	$	45

9. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
	Dec 31 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Current corporate income tax (recovery) expense – North America	**$ (66)**	$ 123	**$ 86**	$ 702
Current corporate income tax recovery – North Sea	**(18)**	(23)	**(117)**	(68)
Current corporate income tax expense – Offshore Africa	**5**	8	**17**	43
Current PRT [1] recovery – North Sea	**(71)**	(86)	**(258)**	(273)
Other taxes	**2**	5	**11**	23
Current income tax (recovery) expense	**(148)**	27	**(261)**	427
Deferred corporate income tax (recovery) expense	**(1)**	254	**216**	681
Deferred PRT [1] (recovery) expense – North Sea	**(32)**	(1)	**15**	126
Deferred income tax (recovery) expense	**(33)**	253	**231**	807
Income tax (recovery) expense	**$ (181)**	$ 280	**$ (30)**	$ 1,234

(1) Petroleum Revenue Tax.

In June 2015, the Alberta government enacted legislation that increased the provincial corporate income tax rate from 10% to 12% effective July 1, 2015. As a result of this income tax rate increase, the Company's deferred income tax liability was increased by $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 are 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 these income tax changes, the Company's deferred income tax liability was reduced by $217 million and the deferred PRT liability was reduced by $11 million.

10. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2015	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,091,837**	**$ 4,432**
Issued upon exercise of stock options	**2,831**	**91**
Previously recognized liability on stock options exercised for common shares	**–**	**18**
Balance – end of year	**1,094,668**	**$ 4,541**

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 2, 2016, the Board of Directors declared a regular quarterly dividend of $0.23 per common share ($0.23 per common share, declared on March 4, 2015).

Normal Course Issuer Bid

In April 2015, the Company announced 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, during the twelve month period commencing April 2015 and ending April 2016, up to 54,640,607 common shares. The Company's Normal Course Issuer Bid announced in 2014 expired April 2015.

For the year ended December 31, 2015, the Company did not purchase any common shares for cancellation.

Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2015:

	Year Ended Dec 31, 2015		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**71,708**	**$**	**35.60**
Granted	**13,310**	**$**	**30.56**
Surrendered for cash settlement	**(185)**	**$**	**33.30**
Exercised for common shares	**(2,831)**	**$**	**32.31**
Forfeited	**(7,387)**	**$**	**35.12**
Outstanding – end of year	**74,615**	**$**	**34.88**
Exercisable – end of year	**30,567**	**$**	**36.19**

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 2015		Dec 31 2014
Derivative financial instruments designated as cash flow hedges	**$**	**58**	$	94
Foreign currency translation adjustment		**17**		(43)
	$	**75**	$	51

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, 2015, the ratio was within the target range at 38%.

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 2015	Dec 31 2014
Long-term debt [1]	**$ 16,794**	$ 14,002
Total shareholders' equity	**$ 27,381**	$ 28,891
Debt to book capitalization	**38%**	33%

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

13. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Weighted average common shares outstanding – basic (thousands of shares)	**1,094,528**	1,091,427	**1,093,862**	1,091,754
Effect of dilutive stock options (thousands of shares)	**299**	3,054	**–**	5,068
Weighted average common shares outstanding – diluted (thousands of shares)	**1,094,827**	1,094,481	**1,093,862**	1,096,822
Net earnings (loss)	**$ 131**	$ 1,198	**$ (637)**	$ 3,929
Net earnings (loss) per common share – basic	**$ 0.12**	$ 1.10	**$ (0.58)**	$ 3.60
– diluted	**$ 0.12**	$ 1.09	**$ (0.58)**	$ 3.58

14. FINANCIAL INSTRUMENTS

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

Dec 31, 2015									
Asset (liability)		**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**
Investment in PrairieSky		**–**		**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)**

Dec 31, 2014										
Asset (liability)		Financial assets at amortized cost		Fair value through profit or loss		Derivatives used for hedging		Financial liabilities at amortized cost		Total
Accounts receivable	$	1,889	$	–	$	–	$	–	$	1,889
Other long-term assets		120		415		184		–		719
Accounts payable		–		–		–		(564)		(564)
Accrued liabilities		–		–		–		(3,279)		(3,279)
Other long-term liabilities		–		–		–		(40)		(40)
Long-term debt [1]		–		–		–		(14,002)		(14,002)
	$	2,009	$	415	$	184	$	(17,885)	$	(15,277)

(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 as noted below. The fair values of the Company's recurring other long-term assets and fixed rate long-term debt are outlined below:

Dec 31, 2015								
	Carrying		**Fair value**					
Asset (liability) [1] [2]				**Level 1**		**Level 2**		**Level 3**
Investment in PrairieSky [3]	**$**	**974**	**$**	**974**	**$**	**–**	**$**	**–**
Other long-term assets [4]	**$**	**1,108**	**$**	**–**	**$**	**854**	**$**	**254**
Fixed rate long-term debt [5] [6]	**$**	**(12,808)**	**$**	**(12,431)**	**$**	**–**	**$**	**–**

Dec 31, 2014								
	Carrying amount		Fair value					
Asset (liability) [1] [2]				Level 1		Level 2		Level 3
Other long-term assets [4]	$	719	$	–	$	599	$	120
Fixed rate long-term debt [5] [6]	$	(11,018)	$	(11,855)	$	–	$	–

(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 investment in PrairieSky is 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, 2015**	Dec 31, 2014
Derivatives held for trading		
Crude oil price collars	**$ –**	$ 410
Crude oil WCS [(1)] differential swaps	**–**	(16)
Foreign currency forward contracts	**36**	21
Cash flow hedges		
Foreign currency forward contracts	**30**	11
Cross currency swaps	**788**	173
	$ 854	$ 599
Included within:		
Current portion of other long-term assets	**$ 305**	$ 436
Other long-term assets	**549**	163
	$ 854	$ 599

(1) Western Canadian Select.

For the year ended December 31, 2015, the Company recognized a gain of $5 million (year ended December 31, 2014 – loss of $3 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 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 (liability) were recognized in the financial statements as follows:

Asset (liability)	**Dec 31, 2015**	Dec 31, 2014
Balance – beginning of year	**$ 599**	$ (136)
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**(374)**	451
Foreign exchange	**669**	270
Other comprehensive (loss) income	**(40)**	14
Balance – end of year	**854**	599
Less: current portion	**305**	436
	$ 549	$ 163

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

	Three Months Ended		Year Ended	
	Dec 31 2015	Dec 31 2014	**Dec 31 2015**	Dec 31 2014
Net realized risk management gain	**$ (255)**	$ (335)	**$ (843)**	$ (349)
Net unrealized risk management loss (gain)	**174**	(404)	**374**	(451)
	$ (81)	$ (739)	**$ (469)**	$ (800)

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, 2015, the Company had no commodity derivative financial instruments outstanding.

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, 2015 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, 2015, 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 2016 – Mar 2016	US$500	1.109	Three-month LIBOR plus 0.375%	Three-month CDOR (1) plus 0.309%
	Jan 2016 – Aug 2016	US$250	1.116	6.00%	5.40%
	Jan 2016 – May 2017	US$1,100	1.170	5.70%	5.10%
	Jan 2016 – Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2016 – Mar 2038	US$550	1.170	6.25%	5.76%

(1) Canadian Dealer Offered Rate ("CDOR").

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2015 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2015, the Company had US$2,357 million of foreign currency forward contracts outstanding, with terms of approximately 30 days or less, including US$1,157 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, 2015, 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, 2015, the Company had net risk management assets of $854 million with specific counterparties related to derivative financial instruments (December 31, 2014 – $622 million).

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	$ 571	$ –	$ –	$ –
Accrued liabilities	$ 2,089	$ –	$ –	$ –
Long-term debt (1)	$ 1,730	$ 2,522	$ 5,679	$ 6,935

(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:

	2016	2017	2018	2019	2020	Thereafter
Product transportation and pipeline	$ 423	$ 341	$ 303	$ 261	$ 246	$ 1,304
Offshore equipment operating leases and offshore drilling	$ 247	$ 93	$ 71	$ 22	$ –	$ –
Office leases	$ 42	$ 42	$ 42	$ 43	$ 42	$ 193
Other	$ 141	$ 38	$ 48	$ 1	$ –	$ –

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)	Exploration and Production															
	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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**1,970**	3,586	**9,222**	15,963	**133**	205	**638**	701	**148**	111	**482**	503	**2,251**	3,902	**10,342**	17,167
Less: royalties	**(151)**	(407)	**(732)**	(2,159)	**–**	–	**(1)**	(2)	**(7)**	(8)	**(22)**	(43)	**(158)**	(415)	**(755)**	(2,204)
Segmented revenue	**1,819**	3,179	**8,490**	13,804	**133**	205	**637**	699	**141**	103	**460**	460	**2,093**	3,487	**9,587**	14,963
Segmented expenses																
Production	**592**	754	**2,603**	2,924	**110**	171	**544**	496	**67**	74	**223**	212	**769**	999	**3,370**	3,632
Transportation and blending	**554**	757	**2,309**	3,228	**18**	2	**61**	5	**1**	–	**2**	1	**573**	759	**2,372**	3,234
Depletion, depreciation and amortization	**1,065**	1,059	**4,248**	3,901	**107**	120	**388**	269	**158**	31	**273**	105	**1,330**	1,210	**4,909**	4,275
Asset retirement obligation accretion	**23**	25	**93**	98	**10**	10	**39**	38	**2**	2	**10**	10	**35**	37	**142**	146
Realized risk management activities	**(255)**	(335)	**(843)**	(349)	**–**	–	**–**	–	**–**	–	**–**	–	**(255)**	(335)	**(843)**	(349)
Gains on disposition of properties and corporate acquisitions	**(690)**	(137)	**(739)**	(137)	**–**	–	**–**	–	**–**	–	**–**	–	**(690)**	(137)	**(739)**	(137)
Loss from investments	**6**	–	**6**	–	**–**	–	**–**	–	**–**	–	**–**	–	**6**	–	**6**	–
Total segmented expenses	**1,295**	2,123	**7,677**	9,665	**245**	303	**1,032**	808	**228**	107	**508**	328	**1,768**	2,533	**9,217**	10,801
Segmented earnings (loss) before the following	**524**	1,056	**813**	4,139	**(112)**	(98)	**(395)**	(109)	**(87)**	(4)	**(48)**	132	**325**	954	**370**	4,162
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Unrealized risk management activities																
Foreign exchange loss																
Total non-segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax (recovery) expense																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter-segment elimination and other				Total			
	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	
	2015	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014	**2015**	2014
Segmented product sales	**693**	932	**2,764**	4,095	**33**	29	**136**	120	**(14)**	(13)	**(75)**	(81)	**2,963**	4,850	**13,167**	21,301
Less: royalties	**(12)**	(51)	**(49)**	(234)	**–**	–	**–**	–	**–**	–	**–**	–	**(170)**	(466)	**(804)**	(2,438)
Segmented revenue	**681**	881	**2,715**	3,861	**33**	29	**136**	120	**(14)**	(13)	**(75)**	(81)	**2,793**	4,384	**12,363**	18,863
Segmented expenses																
Production	**344**	395	**1,332**	1,609	**7**	7	**32**	34	**(1)**	(2)	**(8)**	(10)	**1,119**	1,399	**4,726**	5,265
Transportation and blending	**20**	20	**82**	75	**–**	–	**–**	–	**(18)**	(20)	**(75)**	(77)	**575**	759	**2,379**	3,232
Depletion, depreciation and amortization	**139**	194	**562**	596	**3**	2	**12**	9	**–**	–	**–**	–	**1,472**	1,406	**5,483**	4,880
Asset retirement obligation accretion	**8**	12	**31**	47	**–**	–	**–**	–	**–**	–	**–**	–	**43**	49	**173**	193
Realized risk management activities	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(255)**	(335)	**(843)**	(349)
Gains on disposition of properties and corporate acquisitions	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**–**	–	**(690)**	(137)	**(739)**	(137)
Loss from investments	**–**	–	**–**	–	**12**	5	**44**	8	**–**	–	**–**	–	**18**	5	**50**	8
Total segmented expenses	**511**	621	**2,007**	2,327	**22**	14	**88**	51	**(19)**	(22)	**(83)**	(87)	**2,282**	3,146	**11,229**	13,092
Segmented earnings (loss) before the following	**170**	260	**708**	1,534	**11**	15	**48**	69	**5**	9	**8**	6	**511**	1,238	**1,134**	5,771
Non-segmented expenses																
Administration													**93**	100	**390**	367
Share-based compensation													**56**	(144)	**(46)**	66
Interest and other financing expense													**73**	84	**322**	323
Unrealized risk management activities													**174**	(404)	**374**	(451)
Foreign exchange loss													**165**	124	**761**	303
Total non-segmented expenses													**561**	(240)	**1,801**	608
Earnings (loss) before taxes													**(50)**	1,478	**(667)**	5,163
Current income tax (recovery) expense													**(148)**	27	**(261)**	427
Deferred income tax (recovery) expense													**(33)**	253	**231**	807
Net earnings (loss)													**131**	1,198	**(637)**	3,929

Capital Expenditures [(1)]

	Year Ended					
	Dec 31, 2015			Dec 31, 2014		
	Net expenditures (proceeds)[(2)]	**Non-cash and fair value changes**[(3)]	**Capitalized costs**	Net expenditures	Non-cash and fair value changes[(3)]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [(4)]	**$ (260)**	**$ (666)**	**$ (926)**	$ 1,103	$ (247)	$ 856
North Sea	**–**	**–**	**–**	–	–	–
Offshore Africa	**35**	**(96)**	**(61)**	87	–	87
	$ (225)	**$ (762)**	**$ (987)**	$ 1,190	$ (247)	$ 943
Property, plant and equipment						
Exploration and Production						
North America [(4)]	**$ 1,171**	**$ (1,237)**	**$ (66)**	$ 6,397	$ 399	$ 6,796
North Sea	**230**	**(217)**	**13**	400	86	486
Offshore Africa	**573**	**(49)**	**524**	194	(1)	193
	1,974	**(1,503)**	**471**	6,991	484	7,475
Oil Sands Mining and Upgrading [(5)]	**2,730**	**(335)**	**2,395**	3,110	(528)	2,582
Midstream	**8**	**(1)**	**7**	62	–	62
Head office	**26**	**–**	**26**	45	(1)	44
	$ 4,738	**$ (1,839)**	**$ 2,899**	$ 10,208	$ (45)	$ 10,163

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

(2) Net expenditures (proceeds) in 2015 do not include non-cash share consideration of $985 million received from PrairieSky on the disposition of royalty income assets in the fourth quarter of 2015.

(3) Asset retirement obligations, deferred income tax adjustments related to differences between carrying amounts and tax values, transfers of exploration and evaluation assets, and other fair value adjustments.

(4) The above noted figures in 2015 do not include the impact of other pre-tax gains on the sale of other properties totaling $49 million recognized in the third quarter of 2015.

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

Segmented Assets

		Dec 31 2015		Dec 31 2014
Exploration and Production				
North America	**$**	**30,937**	$	34,382
North Sea		**2,734**		2,711
Offshore Africa		**1,755**		1,214
Other		**73**		18
Oil Sands Mining and Upgrading		**22,598**		20,702
Midstream		**1,054**		1,048
Head office		**124**		125
	$	**59,275**	$	60,200

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, 2015:

Interest coverage (times)	
Net earnings (loss) [(1)]	(0.2)x
Cash flow from operations [(2)]	10.8x

(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) Cash 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.

CONFERENCE CALL

A conference call will be held at 9:00 a.m. Mountain Time, 11:00 a.m. Eastern Time on Thursday, March 3, 2016. The North American conference call number is 1-877-223-4471 and the outside North American conference call number is 001-647-788-4922. Please call in about 10 minutes before the starting time in order to be patched into the call.

A taped rebroadcast will be available until 6:00 p.m. Mountain Time, Thursday, March 17, 2016. To access the rebroadcast in North America, dial 1-800-585-8367. Those outside of North America, dial 001-416-621-4642. The conference ID number to use is 79068863.

WEBCAST

This call is being webcast and can be accessed on Canadian Natural's website at www.cnrl.com.

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