

MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

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

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and 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 and nine months ended September 30, 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 September 30, 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 and nine months ended September 30, 2015 in relation to the comparable periods in 2014 and the second 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 November 3, 2015.

FINANCIAL HIGHLIGHTS

(\$ millions, except per common share amounts)

| | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Product sales | \$ 3,316 | \$ 3,662 | \$ 5,370 | \$ 10,204 | \$ 16,451 |
| Net earnings (loss) | \$ (111) | \$ (405) | \$ 1,039 | \$ (768) | \$ 2,731 |
| Per common share – basic | \$ (0.10) | \$ (0.37) | \$ 0.95 | \$ (0.70) | \$ 2.50 |
| – diluted | \$ (0.10) | \$ (0.37) | \$ 0.94 | \$ (0.70) | \$ 2.49 |
| Adjusted net earnings from operations ⁽¹⁾ | \$ 113 | \$ 178 | \$ 984 | \$ 312 | \$ 3,055 |
| Per common share – basic | \$ 0.10 | \$ 0.16 | \$ 0.90 | \$ 0.28 | \$ 2.80 |
| – diluted | \$ 0.10 | \$ 0.16 | \$ 0.89 | \$ 0.28 | \$ 2.78 |
| Cash flow from operations ⁽²⁾ | \$ 1,533 | \$ 1,503 | \$ 2,440 | \$ 4,406 | \$ 7,219 |
| Per common share – basic | \$ 1.40 | \$ 1.38 | \$ 2.23 | \$ 4.03 | \$ 6.61 |
| – diluted | \$ 1.40 | \$ 1.37 | \$ 2.21 | \$ 4.02 | \$ 6.57 |
| Capital expenditures, net of dispositions | \$ 1,240 | \$ 1,297 | \$ 2,175 | \$ 3,949 | \$ 9,524 |

(1) Adjusted net earnings 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 from Operations

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Net earnings (loss) as reported | \$ (111) | \$ (405) | \$ 1,039 | \$ (768) | \$ 2,731 |
| Share-based compensation, net of tax ⁽¹⁾ | (87) | (79) | (122) | (102) | 210 |
| Unrealized risk management (gain) loss, net of tax ⁽²⁾ | (24) | 162 | (118) | 147 | (36) |
| Unrealized foreign exchange loss (gain), net of tax ⁽³⁾ | 351 | (76) | 185 | 688 | 150 |
| Equity loss (gain) from investment, net of tax ⁽⁴⁾ | 20 | (3) | – | 32 | – |
| Gain on disposition of properties, net of tax ⁽⁵⁾ | (36) | – | – | (36) | – |
| Effect of statutory tax rate and other legislative changes on deferred income tax liabilities ⁽⁶⁾ | – | 579 | – | 351 | – |
| Adjusted net earnings from operations | \$ 113 | \$ 178 | \$ 984 | \$ 312 | \$ 3,055 |

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

(5) 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.

(6) 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 | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Net earnings (loss) | \$ (111) | \$ (405) | \$ 1,039 | \$ (768) | \$ 2,731 |
| Non-cash items: | | | | | |
| Depletion, depreciation and amortization | 1,376 | 1,280 | 1,226 | 4,011 | 3,474 |
| Share-based compensation | (87) | (79) | (122) | (102) | 210 |
| Asset retirement obligation accretion | 44 | 43 | 49 | 130 | 144 |
| Unrealized risk management (gain) loss | (29) | 215 | (150) | 200 | (47) |
| Unrealized foreign exchange loss (gain) | 351 | (76) | 185 | 688 | 150 |
| Equity loss (gain) from investment | 20 | (3) | 5 | 32 | 3 |
| Deferred income tax expense | 18 | 528 | 208 | 264 | 554 |
| Gain on disposition of properties | (49) | – | – | (49) | – |
| Cash flow from operations | \$ 1,533 | \$ 1,503 | \$ 2,440 | \$ 4,406 | \$ 7,219 |

SUMMARY OF CONSOLIDATED NET EARNINGS AND CASH FLOW FROM OPERATIONS

Net loss for the nine months ended September 30, 2015 was \$768 million compared with net earnings of \$2,731 million for the nine months ended September 30, 2014. Net loss for the nine months ended September 30, 2015 included net after-tax expenses of \$1,080 million compared with \$324 million for the nine months ended September 30, 2014 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity loss from investment, gain on disposition of properties, 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 nine months ended September 30, 2015 were \$312 million compared with \$3,055 million for the nine months ended September 30, 2014.

Net loss for the third quarter of 2015 was \$111 million compared with net earnings of \$1,039 million for the third quarter of 2014 and net loss of \$405 million for the second quarter of 2015. Net loss for the third quarter of 2015 included net after-tax expenses of \$224 million compared with net after-tax income of \$55 million for the third quarter of 2014 and net after-tax expenses of \$583 million for the second quarter of 2015 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, equity loss (gain) from investment, gain on disposition of properties, 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 third quarter of 2015 were \$113 million compared with \$984 million for the third quarter of 2014 and \$178 million for the second quarter of 2015.

The decrease in adjusted net earnings for the nine months ended September 30, 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 third quarter of 2015 from the third 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 crude oil and NGLs and natural gas sales volumes in the North America segment; and
- higher depletion, depreciation and amortization expense;

partially offset by:

- higher crude oil and natural gas and SCO sales volumes in the International and Oil Sands Mining and Upgrading 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 third quarter of 2015 from the second quarter of 2015 was primarily due to:

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

partially offset by:

- higher SCO and crude oil and NGLs sales volumes in the Oil Sands Mining and Upgrading, North America and Offshore Africa segments;
- higher realized risk management gains; 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 nine months ended September 30, 2015 was \$4,406 million compared with \$7,219 million for the nine months ended September 30, 2014. Cash flow from operations for the third quarter of 2015 was \$1,533 million compared with \$2,440 million for the third quarter of 2014 and \$1,503 million for the second 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 nine months ended September 30, 2015 increased 11% to 850,587 BOE/d from 766,871 BOE/d for the nine months ended September 30, 2014. Total production before royalties for the third quarter of 2015 increased 6% to 848,701 BOE/d from 796,931 BOE/d for the third quarter of 2014 and increased 5% from 805,547 BOE/d for the second 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) | Sep 30 2015 | Jun 30 2015 | Mar 31 2015 | Dec 31 2014 |
|--|----------------|----------------|----------------|----------------|
| Product sales | \$ 3,316 | \$ 3,662 | \$ 3,226 | \$ 4,850 |
| Net earnings (loss) | \$ (111) | \$ (405) | \$ (252) | \$ 1,198 |
| Net earnings (loss) per common share | | | | |
| – basic | \$ (0.10) | \$ (0.37) | \$ (0.23) | \$ 1.10 |
| – diluted | \$ (0.10) | \$ (0.37) | \$ (0.23) | \$ 1.09 |
| (\$ millions, except per common share amounts) | Sep 30 2014 | Jun 30 2014 | Mar 31 2014 | Dec 31 2013 |
| Product sales | \$ 5,370 | \$ 6,113 | \$ 4,968 | \$ 4,330 |
| Net earnings (loss) | \$ 1,039 | \$ 1,070 | \$ 622 | \$ 413 |
| Net earnings (loss) per common share | | | | |
| – basic | \$ 0.95 | \$ 0.98 | \$ 0.57 | \$ 0.38 |
| – diluted | \$ 0.94 | \$ 0.97 | \$ 0.57 | \$ 0.38 |

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, 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, the heavy crude oil drilling program, the impact and timing of acquisitions, and the impact of turnarounds at Horizon. 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 pricing, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand 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 depletion, depreciation and amortization expense in the North Sea resulting from the planned early cessation of production at the Murchison platform, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based 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 acquisitions/disposition of properties** – Fluctuations due to the recognition of gains on dispositions in the third quarter of 2015 and acquisitions in the fourth quarter of 2014.

BUSINESS ENVIRONMENT

| | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| WTI benchmark price (US\$/bbl) | \$ 46.44 | \$ 57.96 | \$ 97.21 | \$ 50.98 | \$ 99.60 |
| Dated Brent benchmark price (US\$/bbl) | \$ 50.39 | \$ 61.95 | \$ 101.90 | \$ 55.37 | \$ 106.55 |
| WCS blend differential from WTI (US\$/bbl) | \$ 13.21 | \$ 11.60 | \$ 20.19 | \$ 13.18 | \$ 21.15 |
| WCS blend differential from WTI (%) | 28% | 20% | 21% | 26% | 21% |
| SCO price (US\$/bbl) | \$ 45.78 | \$ 60.61 | \$ 94.31 | \$ 50.55 | \$ 98.20 |
| Condensate benchmark price (US\$/bbl) | \$ 44.20 | \$ 57.98 | \$ 93.49 | \$ 49.25 | \$ 100.36 |
| NYMEX benchmark price (US\$/MMBtu) | \$ 2.77 | \$ 2.67 | \$ 4.07 | \$ 2.80 | \$ 4.51 |
| AECO benchmark price (C\$/GJ) | \$ 2.65 | \$ 2.53 | \$ 4.00 | \$ 2.66 | \$ 4.32 |
| US/Canadian dollar average exchange rate (US\$) | \$ 0.7640 | \$ 0.8132 | \$ 0.9183 | \$ 0.7936 | \$ 0.9139 |

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. In the third quarter of 2015, realized prices continued to be impacted by the weak 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\$50.98 per bbl for the nine months ended September 30, 2015, a decrease of 49% from US\$99.60 per bbl for the nine months ended September 30, 2014. WTI averaged US\$46.44 per bbl for the third quarter of 2015, a decrease of 52% from US\$97.21 per bbl for the third quarter of 2014, and a decrease of 20% from US\$57.96 per bbl for the second 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\$55.37 per bbl for the nine months ended September 30, 2015, a decrease of 48% from US\$106.55 per bbl for the nine months ended September 30, 2014. Brent averaged US\$50.39 per bbl for the third quarter of 2015, a decrease of 51% from US\$101.90 per bbl for the third quarter of 2014, and a decrease of 19% from US\$61.95 per bbl for the second 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 together with the Organization of the Petroleum Exporting Countries' ("OPEC") decision to continue to maintain crude oil production quotas resulted in a decline in year-over-year benchmark pricing.

The WCS Heavy Differential averaged 26% for the nine months ended September 30, 2015, compared with 21% for the nine months ended September 30, 2014. The WCS Heavy Differential averaged 28% for the third quarter of 2015 compared with 21% for the third quarter of 2014 and 20% for the second quarter of 2015. The WCS Heavy Differential widened for the third quarter of 2015 from the second quarter of 2015 primarily due to planned and unplanned refinery shutdowns in the US Midwest.

The WCS Heavy Differential is expected to continue to reflect seasonal demand fluctuations, changes in transportation logistics, and refinery utilization and shutdowns.

The SCO price averaged US\$50.55 per bbl for the nine months ended September 30, 2015, a decrease of 49% from US\$98.20 per bbl for the nine months ended September 30, 2014. The SCO price averaged US\$45.78 per bbl for the third quarter of 2015, a decrease of 51% from US\$94.31 per bbl for the third quarter of 2014, and a decrease of 24% from US\$60.61 per bbl for the second quarter of 2015. The fluctuations in SCO pricing for the three and nine months ended September 30, 2015 from the comparable periods were primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US\$2.80 per MMBtu for the nine months ended September 30, 2015, a decrease of 38% from US\$4.51 per MMBtu for the nine months ended September 30, 2014. NYMEX natural gas prices averaged US\$2.77 per MMBtu for the third quarter of 2015, a decrease of 32% from US\$4.07 per MMBtu for the third quarter of 2014, and an increase of 4% from US\$2.67 per MMBtu for the second quarter of 2015.

AECO natural gas prices for the nine months ended September 30, 2015 averaged \$2.66 per GJ, a decrease of 38% from \$4.32 per GJ for the nine months ended September 30, 2014. AECO natural gas prices for the third quarter of 2015 averaged \$2.65 per GJ, a decrease of 34% from \$4.00 per GJ for the third quarter of 2014, and an increase of 5% from \$2.53 per GJ for the second quarter of 2015.

In the third quarter of 2015, natural gas pricing was comparable with the second quarter of 2015. US natural gas production was comparable between the second and third quarters of 2015 with natural gas inventories growing slightly above normal levels. Natural gas prices were lower in the third quarter of 2015 than the third quarter of 2014 primarily due to lower than average storage levels in 2014 as a result of the colder than normal winter temperatures.

DAILY PRODUCTION, before royalties

| | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (bbl/d) | | | | | |
| North America – Exploration and Production | 397,892 | 375,040 | 404,114 | 401,657 | 384,356 |
| North America – Oil Sands Mining and Upgrading ⁽¹⁾ | 131,779 | 96,607 | 82,012 | 120,842 | 104,667 |
| North Sea | 22,387 | 20,330 | 18,197 | 21,915 | 15,848 |
| Offshore Africa | 21,077 | 17,070 | 13,684 | 17,140 | 12,557 |
| | 573,135 | 509,047 | 518,007 | 561,554 | 517,428 |
| Natural gas (MMcf/d) | | | | | |
| North America | 1,592 | 1,716 | 1,644 | 1,673 | 1,468 |
| North Sea | 35 | 38 | 7 | 36 | 7 |
| Offshore Africa | 26 | 25 | 23 | 25 | 22 |
| | 1,653 | 1,779 | 1,674 | 1,734 | 1,497 |
| Total barrels of oil equivalent (BOE/d) | 848,701 | 805,547 | 796,931 | 850,587 | 766,871 |
| Product mix | | | | | |
| Light and medium crude oil and NGLs | 15% | 16% | 16% | 15% | 15% |
| Pelican Lake heavy crude oil | 6% | 6% | 7% | 6% | 6% |
| Primary heavy crude oil | 15% | 16% | 18% | 16% | 19% |
| Bitumen (thermal oil) | 16% | 13% | 14% | 15% | 14% |
| Synthetic crude oil ⁽¹⁾ | 16% | 12% | 10% | 14% | 14% |
| Natural gas | 32% | 37% | 35% | 34% | 32% |
| Percentage of product sales ^{(1) (2)} (excluding Midstream revenue) | | | | | |
| Crude oil and NGLs | 83% | 84% | 85% | 83% | 85% |
| Natural gas | 17% | 16% | 15% | 17% | 15% |

(1) Third quarter 2015 SCO production before royalties excludes 2,058 bbl/d of SCO consumed internally as diesel (second quarter 2015 – 2,410 bbl/d; third quarter 2014 – 875 bbl/d; nine months ended September 30, 2015 – 2,049 bbl/d; nine months ended September 30, 2014 – 295 bbl/d).

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

DAILY PRODUCTION, net of royalties

| | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (bbl/d) | | | | | |
| North America – Exploration and Production | 350,444 | 326,445 | 329,533 | 352,278 | 309,855 |
| North America – Oil Sands Mining and Upgrading | 129,355 | 95,057 | 76,515 | 118,930 | 100,152 |
| North Sea | 22,325 | 20,300 | 18,062 | 21,865 | 15,773 |
| Offshore Africa | 20,145 | 16,342 | 12,276 | 16,386 | 11,600 |
| | 522,269 | 458,144 | 436,386 | 509,459 | 437,380 |
| Natural gas (MMcf/d) | | | | | |
| North America | 1,527 | 1,684 | 1,525 | 1,617 | 1,341 |
| North Sea | 35 | 38 | 7 | 36 | 7 |
| Offshore Africa | 25 | 24 | 19 | 24 | 19 |
| | 1,587 | 1,746 | 1,551 | 1,677 | 1,367 |
| Total barrels of oil equivalent (BOE/d) | 786,734 | 749,210 | 694,859 | 789,030 | 665,214 |

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 nine months ended September 30, 2015 increased 9% to 561,554 bbl/d from 517,428 bbl/d for the nine months ended September 30, 2014. Crude oil and NGLs production for the third quarter of 2015 increased 11% to 573,135 bbl/d from 518,007 bbl/d for the third quarter of 2014 and increased 13% from 509,047 bbl/d for the second quarter of 2015. The increase in production for the three and nine months ended September 30, 2015 from the comparable periods 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 third quarter of 2015 was within the Company's previously issued guidance of 559,000 to 590,000 bbl/d.

Natural gas production for the nine months ended September 30, 2015 increased 16% to 1,734 MMcf/d from 1,497 MMcf/d for the nine months ended September 30, 2014. Natural gas production for the third quarter of 2015 decreased 1% to 1,653 MMcf/d from 1,674 MMcf/d for the third quarter of 2014 and decreased 7% from 1,779 MMcf/d for the second quarter of 2015. The increase in natural gas production for the nine months ended September 30, 2015 from comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014 and growth from higher production volumes in the North Sea. Natural gas production for the three months ended September 30, 2015 decreased from the comparable periods primarily due to third party transmission pipeline restrictions in Northwest Alberta, involving certain transmission pipeline operators. The Company shut in total natural gas volumes averaging approximately 105 MMcf/d, higher than the 80 MMcf/d originally expected. These additional pipeline restrictions resulted in natural gas production of 1,653 MMcf/d for the third quarter of 2015, slightly below the Company's previously issued guidance of 1,670 to 1,690 MMcf/d.

2015 annual production guidance is now targeted to average between 555,000 and 591,000 bbl/d of crude oil and NGLs and between 1,730 and 1,770 MMcf/d of natural gas. Fourth quarter 2015 production guidance is targeted to average between 562,000 and 588,000 bbl/d of crude oil and NGLs and between 1,735 and 1,775 MMcf/d of natural gas.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2015 increased 5% to average 401,657 bbl/d from 384,356 bbl/d for the nine months ended September 30, 2014. For the third quarter of 2015, crude oil and NGLs production decreased 2% to average 397,892 bbl/d compared with 404,114 bbl/d for the third quarter of 2014 and increased 6% from 375,040 bbl/d for the second quarter of 2015. The increase in production for the nine months ended September 30, 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 increase in production for the third quarter of 2015 from the second quarter of 2015 was primarily due to the reinstatement of production in the thermal production areas after the forest fires in Northeastern Alberta in the second quarter of 2015. Third quarter 2015 production of crude oil and NGLs was within the Company's previously issued guidance of 393,000 to 413,000 bbl/d. Fourth quarter 2015 production guidance is targeted to average between 388,000 and 404,000 bbl/d of crude oil and NGLs.

Natural gas production for the nine months ended September 30, 2015 increased 14% to 1,673 MMcf/d compared with 1,468 MMcf/d for the nine months ended September 30, 2014. Natural gas production decreased 3% to 1,592 MMcf/d for the third quarter of 2015 compared with 1,644 MMcf/d in the third quarter of 2014 and decreased 7% from 1,716 for the second quarter of 2015. The increase in natural gas production for the nine months ended September 30, 2015 from the comparable period was primarily a result of acquisitions of producing Canadian natural gas properties in 2014. Natural gas production for the three months ended September 30, 2015 decreased from the comparable periods primarily due to third party transmission pipeline restrictions in Northwest Alberta, involving certain transmission pipeline operators. The Company shut in total natural gas volumes averaging approximately 105 MMcf/d, higher than the 80 MMcf/d originally expected.

North America – Oil Sands Mining and Upgrading

SCO production for the nine months ended September 30, 2015 increased 15% to 120,842 bbl/d from 104,667 bbl/d for the nine months ended September 30, 2014. For the third quarter of 2015, SCO production increased 61% to 131,779 bbl/d from 82,012 bbl/d for the third quarter of 2014 and increased 36% from 96,607 bbl/d for the second quarter of 2015. Production in the third 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. Third quarter 2015 production of SCO exceeded the Company's previously issued guidance of 124,000 to 131,000 bbl/d. Fourth quarter 2015 production guidance targeted to average between 123,000 to 129,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2015 increased 38% to 21,915 bbl/d from 15,848 bbl/d for the nine months ended September 30, 2014. Third quarter 2015 crude oil production increased 23% to 22,387 bbl/d from 18,197 bbl/d for the third quarter of 2014, and increased 10% from 20,330 bbl/d for the second quarter of 2015. The increase in production for the three and nine months ended September 30, 2015 from the comparable periods in 2014 primarily reflected the reinstatement of production from both the Banff FPSO and the Tiffany platform in 2014. The increase in production for the third quarter of 2015 from the second quarter of 2015 was primarily due to the impact of planned turnarounds performed at the Ninian platforms.

Offshore Africa

Offshore Africa crude oil production increased 36% to 17,140 bbl/d for the nine months ended September 30, 2015 from 12,557 bbl/d for the nine months ended September 30, 2014. Third quarter 2015 crude oil production increased 54% to 21,077 bbl/d from 13,684 bbl/d for the third quarter of 2014 and increased 23% from 17,070 bbl/d for the second quarter of 2015. The increase in production volumes for the three and nine months ended September 30, 2015 from the comparable periods was due to new wells on stream at both the Espoir and the Baobab fields in the second and third quarters of 2015, partially offset by natural field declines.

International Guidance

The Company's North Sea and Offshore Africa third quarter 2015 crude oil production was 43,464 bbl/d and was within the Company's previously issued guidance of 42,000 to 46,000 bbl/d. Fourth quarter 2015 production guidance is targeted to average between 51,000 and 55,000 bbl/d of crude oil.

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 on crude oil volumes that were stored in various storage facilities, pipelines, or FPSOs, as follows:

| (bbl) | Sep 30 2015 | Jun 30 2015 | Dec 31 2014 |
|--|------------------|----------------|----------------|
| North America – Exploration and Production | 424,270 | 839,720 | 930,116 |
| North America – Oil Sands Mining and Upgrading (SCO) | 1,327,603 | 1,074,964 | 1,266,063 |
| North Sea | 450,023 | 131,959 | 368,808 |
| Offshore Africa | 1,353,011 | 1,459,094 | 461,997 |
| | 3,554,907 | 3,505,737 | 3,026,984 |

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

| | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (\$/bbl) ⁽¹⁾ | | | | | |
| Sales price ⁽²⁾ | \$ 41.55 | \$ 53.09 | \$ 79.99 | \$ 43.58 | \$ 82.35 |
| Transportation | 2.56 | 2.80 | 2.32 | 2.60 | 2.51 |
| Realized sales price, net of transportation | 38.99 | 50.29 | 77.67 | 40.98 | 79.84 |
| Royalties | 4.09 | 5.91 | 13.66 | 4.57 | 14.46 |
| Production expense | 15.70 | 17.01 | 15.99 | 16.25 | 18.08 |
| Netback | \$ 19.20 | \$ 27.37 | \$ 48.02 | \$ 20.16 | \$ 47.30 |
| Natural gas (\$/Mcf) ⁽¹⁾ | | | | | |
| Sales price ⁽²⁾ | \$ 3.22 | \$ 3.06 | \$ 4.54 | \$ 3.22 | \$ 5.03 |
| Transportation | 0.39 | 0.38 | 0.26 | 0.38 | 0.27 |
| Realized sales price, net of transportation | 2.83 | 2.68 | 4.28 | 2.84 | 4.76 |
| Royalties | 0.11 | 0.05 | 0.32 | 0.09 | 0.43 |
| Production expense | 1.31 | 1.39 | 1.45 | 1.38 | 1.52 |
| Netback | \$ 1.41 | \$ 1.24 | \$ 2.51 | \$ 1.37 | \$ 2.81 |
| Barrels of oil equivalent (\$/BOE) ⁽¹⁾ | | | | | |
| Sales price ⁽²⁾ | \$ 33.46 | \$ 38.85 | \$ 59.56 | \$ 34.22 | \$ 62.38 |
| Transportation | 2.56 | 2.67 | 2.08 | 2.56 | 2.24 |
| Realized sales price, net of transportation | 30.90 | 36.18 | 57.48 | 31.66 | 60.14 |
| Royalties | 2.81 | 3.58 | 9.12 | 3.01 | 9.97 |
| Production expense | 12.68 | 13.39 | 13.15 | 13.09 | 14.68 |
| Netback | \$ 15.41 | \$ 19.21 | \$ 35.21 | \$ 15.56 | \$ 35.49 |

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (\$/bbl) ^{(1) (2)} | | | | | |
| North America | \$ 39.26 | \$ 50.96 | \$ 78.38 | \$ 41.42 | \$ 80.09 |
| North Sea | \$ 62.28 | \$ 73.57 | \$ 113.08 | \$ 67.38 | \$ 120.76 |
| Offshore Africa | \$ 65.31 | \$ 74.84 | \$ 104.82 | \$ 69.23 | \$ 111.25 |
| Company average | \$ 41.55 | \$ 53.09 | \$ 79.99 | \$ 43.58 | \$ 82.35 |
| Natural gas (\$/Mcf) ^{(1) (2)} | | | | | |
| North America | \$ 2.99 | \$ 2.80 | \$ 4.43 | \$ 2.98 | \$ 4.91 |
| North Sea | \$ 9.44 | \$ 9.54 | \$ 6.93 | \$ 9.71 | \$ 6.45 |
| Offshore Africa | \$ 9.01 | \$ 10.49 | \$ 11.73 | \$ 10.34 | \$ 12.05 |
| Company average | \$ 3.22 | \$ 3.06 | \$ 4.54 | \$ 3.22 | \$ 5.03 |
| Company average (\$/BOE) ^{(1) (2)} | \$ 33.46 | \$ 38.85 | \$ 59.56 | \$ 34.22 | \$ 62.38 |

(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 \$41.42 per bbl for the nine months ended September 30, 2015 from \$80.09 per bbl for the nine months ended September 30, 2014. North America realized crude oil prices averaged \$39.26 per bbl for the third quarter of 2015, a decrease of 50% compared with \$78.38 per bbl for the third quarter of 2014 and a decrease of 23% compared with \$50.96 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 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 third quarter of 2015 contributed approximately 165,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 39% to average \$2.98 per Mcf for the nine months ended September 30, 2015 from \$4.91 per Mcf for the nine months ended September 30, 2014. North America realized natural gas prices decreased 33% to average \$2.99 per Mcf for the third quarter of 2015 compared with \$4.43 per Mcf in the third quarter of 2014, and increased 7% compared with \$2.80 per Mcf for the second quarter of 2015. In the third quarter of 2015, realized natural gas pricing was comparable with the second quarter of 2015. US natural gas production was comparable between the second and third quarters of 2015 with natural gas inventories growing slightly above normal levels. Realized natural gas prices were lower in the third quarter of 2015 than the third quarter of 2014 primarily due to lower than average storage levels in 2014 resulting from the colder than normal winter temperatures.

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

| (Quarterly Average) | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 |
|--|------------------------|----------------|----------------|
| Wellhead Price ^{(1) (2)} | | | |
| Light and medium crude oil and NGLs (\$/bbl) | \$ 40.88 | \$ 51.80 | \$ 77.79 |
| Pelican Lake heavy crude oil (\$/bbl) | \$ 39.54 | \$ 54.87 | \$ 81.52 |
| Primary heavy crude oil (\$/bbl) | \$ 39.97 | \$ 53.85 | \$ 79.70 |
| Bitumen (thermal oil) (\$/bbl) | \$ 37.46 | \$ 44.63 | \$ 75.81 |
| Natural gas (\$/Mcf) | \$ 2.99 | \$ 2.80 | \$ 4.43 |

(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 44% to average \$67.38 per bbl for the nine months ended September 30, 2015 from \$120.76 per bbl for the nine months ended September 30, 2014. North Sea realized crude oil prices decreased 45% to average \$62.28 per bbl for the third quarter of 2015 from \$113.08 per bbl for the third quarter of 2014 and decreased 15% from \$73.57 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 38% to average \$69.23 per bbl for the nine months ended September 30, 2015 from \$111.25 per bbl for the nine months ended September 30, 2014. Offshore Africa realized crude oil prices decreased 38% to average \$65.31 per bbl for the third quarter of 2015 from \$104.82 per bbl for the third quarter of 2014 and decreased 13% from \$74.84 per bbl for the second quarter of 2015. The decrease in realized crude oil prices for the three and nine months ended September 30, 2015 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

| | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (\$/bbl) ⁽¹⁾ | | | | | |
| North America | \$ 4.34 | \$ 6.40 | \$ 13.99 | \$ 4.86 | \$ 15.17 |
| North Sea | \$ 0.17 | \$ 0.11 | \$ 0.84 | \$ 0.14 | \$ 0.43 |
| Offshore Africa | \$ 2.89 | \$ 3.19 | \$ 10.79 | \$ 3.04 | \$ 7.77 |
| Company average | \$ 4.09 | \$ 5.91 | \$ 13.66 | \$ 4.57 | \$ 14.46 |
| Natural gas (\$/Mcf) ⁽¹⁾ | | | | | |
| North America | \$ 0.11 | \$ 0.05 | \$ 0.30 | \$ 0.09 | \$ 0.41 |
| Offshore Africa | \$ 0.41 | \$ 0.48 | \$ 1.88 | \$ 0.47 | \$ 1.94 |
| Company average | \$ 0.11 | \$ 0.05 | \$ 0.32 | \$ 0.09 | \$ 0.43 |
| Company average (\$/BOE) ⁽¹⁾ | \$ 2.81 | \$ 3.58 | \$ 9.12 | \$ 3.01 | \$ 9.97 |

(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 and nine months ended September 30, 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 nine months ended September 30, 2015 compared with 20% of product sales for the nine months ended September 30, 2014. Crude oil and NGLs royalties averaged approximately 12% of product sales for the third quarter of 2015 compared with 18% for the third quarter of 2014 and 13% for the second quarter of 2015. The decrease in royalties for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to lower realized crude oil prices. Crude oil and NGLs royalties per bbl are anticipated to average 11.5% to 13.5% of product sales for 2015.

Natural gas royalties averaged approximately 3% of product sales for the nine months ended September 30, 2015 compared with 9% of product sales for the nine months ended September 30, 2014. Natural gas royalties averaged approximately 4% of product sales for the third quarter of 2015 compared with 7% for the third quarter of 2014 and 2% for the second quarter of 2015. The decrease in natural gas royalty rates for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was due to lower realized natural gas prices. The increase in natural gas royalty rates for the third quarter of 2015 from the second quarter of 2015 was due to higher realized natural gas prices. Natural gas royalties are anticipated to average 3% to 4% of product sales for 2015.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the nine months ended September 30, 2015 compared with 9% for the nine months ended September 30, 2014. Royalty rates as a percentage of product sales averaged approximately 4% for the third quarter of 2015 compared with 11% for the third quarter of 2014 and 4% for the second quarter of 2015. The decrease in royalties for the three and nine months ended September 30, 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. Offshore Africa royalty rates are anticipated to average 3.5% to 5.5% of product sales for 2015.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

| | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs (\$/bbl) ⁽¹⁾ | | | | | |
| North America | \$ 11.64 | \$ 13.14 | \$ 14.52 | \$ 12.85 | \$ 15.20 |
| North Sea | \$ 72.69 | \$ 60.61 | \$ 76.48 | \$ 65.64 | \$ 77.31 |
| Offshore Africa | \$ 40.53 | \$ 43.88 | \$ 27.20 | \$ 37.85 | \$ 40.91 |
| Company average | \$ 15.70 | \$ 17.01 | \$ 15.99 | \$ 16.25 | \$ 18.08 |
| Natural gas (\$/Mcf) ⁽¹⁾ | | | | | |
| North America | \$ 1.25 | \$ 1.28 | \$ 1.36 | \$ 1.30 | \$ 1.45 |
| North Sea | \$ 3.85 | \$ 6.47 | \$ 19.21 | \$ 4.80 | \$ 10.58 |
| Offshore Africa | \$ 1.43 | \$ 1.42 | \$ 2.68 | \$ 1.86 | \$ 3.18 |
| Company average | \$ 1.31 | \$ 1.39 | \$ 1.45 | \$ 1.38 | \$ 1.52 |
| Company average (\$/BOE) ⁽¹⁾ | \$ 12.68 | \$ 13.39 | \$ 13.15 | \$ 13.09 | \$ 14.68 |

(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 nine months ended September 30, 2015 decreased 15% to \$12.85 per bbl from \$15.20 per bbl for the nine months ended September 30, 2014. North America crude oil and NGLs production expense for the third quarter of 2015 decreased 20% to \$11.64 per bbl from \$14.52 per bbl for the third quarter of 2014 and decreased 11% from \$13.14 per bbl for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods reflected the Company's continuous focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America crude oil and NGLs production expense is now anticipated to average \$12.25 to \$13.25 per bbl for 2015.

North America natural gas production expense for the nine months ended September 30, 2015 decreased 10% to \$1.30 per Mcf from \$1.45 per Mcf for the nine months ended September 30, 2014. North America natural gas production expense for the third quarter of 2015 decreased 8% to \$1.25 per Mcf from \$1.36 per Mcf for the third quarter of 2014 and decreased 2% from \$1.28 per Mcf for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods reflected the Company's continuous focus on cost control and efficiencies across the asset base, together with lower industry service costs. North America natural gas production expense is anticipated to average \$1.25 to \$1.35 per Mcf for 2015.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2015 decreased 15% to \$65.64 per bbl from \$77.31 per bbl for the nine months ended September 30, 2014. North Sea crude oil production expense for the third quarter of 2015 decreased 5% to \$72.69 per bbl from \$76.48 per bbl for the third quarter of 2014 and increased 20% from \$60.61 per bbl for the second quarter of 2015. The decrease in production expense for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was primarily due to higher production volumes on a relatively fixed cost structure, offset by the impact of the weaker Canadian dollar compared to 2014. The increase in production expense for the third quarter of 2015 from the second quarter of 2015 was primarily due to the timing of liftings from various fields, which have different cost structures, as well as the impact of the weaker Canadian dollar. North Sea crude oil production expense is anticipated to average \$58.00 to \$64.00 per bbl for 2015, reflecting the weakening of the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2015 decreased 7% to \$37.85 per bbl from \$40.91 per bbl for the nine months ended September 30, 2014. Offshore Africa crude oil production expense for the third quarter of 2015 averaged \$40.53 per bbl, an increase of 49% from \$27.20 per bbl for the third quarter of 2014 and a decrease of 8% from \$43.88 per bbl for the second quarter of 2015. The decrease in production expense for the nine months ended September 30, 2015 from the comparable period was primarily due to the impact of higher production volumes. The fluctuations in production expense for the three months ended September 30, 2015 from the comparable periods was primarily due to the timing of liftings from various fields, including Olowi, which have different cost structures, as well as the impact of the weaker Canadian dollar. Offshore Africa crude oil production expense is anticipated to average \$24.00 to \$28.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

| (\$ millions, except per BOE amounts) | Three Months Ended | | | Nine Months Ended | |
|---------------------------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Expense (\$ millions) | \$ 1,208 | \$ 1,158 | \$ 1,087 | \$ 3,579 | \$ 3,065 |
| \$/BOE ⁽¹⁾ | \$ 18.25 | \$ 18.02 | \$ 16.54 | \$ 18.02 | \$ 17.08 |

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

Depletion, depreciation and amortization expense on a per barrel basis for the nine months ended September 30, 2015 increased 6% to \$18.02 per BOE from \$17.08 per BOE for the nine months ended September 30, 2014. Depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2015 increased 10% to \$18.25 per BOE from \$16.54 per BOE for the third quarter of 2014 and was comparable with the second quarter of 2015. The increase for the three and nine months ended September 30, 2015 from the comparable periods in 2014 was primarily related to increased sales volumes in the International segments which have higher associated depletion rates.

The increase in depletion, depreciation and amortization expense for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the increase in sales volumes in 2015.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

| (\$ millions, except per BOE amounts) | Three Months Ended | | | Nine Months Ended | |
|---------------------------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Expense (\$ millions) | \$ 36 | \$ 36 | \$ 37 | \$ 107 | \$ 109 |
| \$/BOE ⁽¹⁾ | \$ 0.54 | \$ 0.55 | \$ 0.56 | \$ 0.54 | \$ 0.60 |

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

Asset retirement obligation accretion expense on a per barrel basis for the nine months ended September 30, 2015 decreased 10% to \$0.54 per BOE from \$0.60 per BOE for the nine months ended September 30, 2014. Asset retirement obligation accretion expense for the third quarter of 2015 decreased 4% to \$0.54 per BOE from \$0.56 per BOE for the third quarter of 2014 and decreased 2% from \$0.55 per BOE for the second quarter of 2015.

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

OPERATIONS UPDATE

The Company continues to focus on reliable and efficient operations. During the third quarter of 2015, operating performance continued to be strong, leading to average production of 131,779 bbl/d, reflecting high utilization rates and reliability.

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

| (\$/bbl) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| SCO sales price ⁽¹⁾ | \$ 60.66 | \$ 73.05 | \$ 103.91 | \$ 62.82 | \$ 108.58 |
| Bitumen value for royalty purposes ^{(1) (2)} | \$ 33.20 | \$ 44.09 | \$ 74.11 | \$ 34.92 | \$ 72.03 |
| Bitumen royalties ^{(1) (3)} | \$ 1.32 | \$ 0.99 | \$ 7.17 | \$ 1.11 | \$ 6.29 |
| Transportation | \$ 1.82 | \$ 1.98 | \$ 2.28 | \$ 1.87 | \$ 1.88 |

(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 \$62.82 per bbl for the nine months ended September 30, 2015, a decrease of 42% compared with \$108.58 per bbl for the nine months ended September 30, 2014. Realized SCO sales prices averaged \$60.66 per bbl for the third quarter of 2015, a decrease of 42% compared with \$103.91 per bbl for the third quarter of 2014 and a decrease of 17% compared with \$73.05 per bbl for the second quarter of 2015. The decrease for the three and nine months ended September 30, 2015 from the comparable periods reflected movements in benchmark pricing and the Canadian dollar.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Cash production costs | \$ 321 | \$ 321 | \$ 398 | \$ 988 | \$ 1,214 |
| Less: costs incurred during turnaround periods | – | (45) | (98) | (45) | (98) |
| Adjusted cash production costs | \$ 321 | \$ 276 | \$ 300 | \$ 943 | \$ 1,116 |
| Adjusted cash production costs, excluding natural gas costs | \$ 300 | \$ 260 | \$ 280 | \$ 886 | \$ 1,027 |
| Adjusted natural gas costs | 21 | 16 | 20 | 57 | 89 |
| Adjusted cash production costs | \$ 321 | \$ 276 | \$ 300 | \$ 943 | \$ 1,116 |

| (\$/bbl) ⁽¹⁾ | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Adjusted cash production costs, excluding natural gas costs | \$ 25.28 | \$ 27.52 | \$ 34.65 | \$ 26.89 | \$ 35.26 |
| Adjusted natural gas costs | 1.76 | 1.73 | 2.48 | 1.74 | 3.05 |
| Adjusted cash production costs | \$ 27.04 | \$ 29.25 | \$ 37.13 | \$ 28.63 | \$ 38.31 |
| Sales (bbl/d) | 129,033 | 103,388 | 87,826 | 120,617 | 106,721 |

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

Adjusted cash production costs for the nine months ended September 30, 2015 decreased 25% to \$28.63 per bbl from \$38.31 per bbl for the nine months ended September 30, 2014. Adjusted cash production costs for the third quarter of 2015 averaged \$27.04 per bbl, a decrease of 27% compared with \$37.13 per bbl for the third quarter of 2014 and a decrease of 8% compared with \$29.25 per bbl for the second quarter of 2015. The decrease in adjusted cash production costs for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, and lower industry service costs. Cash production costs are now anticipated to average \$29.00 to \$32.00 per bbl for 2015.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

| (\$ millions, except per bbl amounts) | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Depletion, depreciation and amortization | \$ 165 | \$ 119 | \$ 137 | \$ 423 | \$ 402 |
| Less: depreciation incurred during turnaround period | – | (5) | (28) | (5) | (28) |
| Adjusted depletion, depreciation and amortization | \$ 165 | \$ 114 | \$ 109 | \$ 418 | \$ 374 |
| \$/bbl ⁽¹⁾ | \$ 13.95 | \$ 12.04 | \$ 13.43 | \$ 12.70 | \$ 12.83 |

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

Adjusted depletion, depreciation and amortization expense on a per barrel basis for the nine months ended September 30, 2015 decreased 1% to \$12.70 per bbl from \$12.83 per bbl for the nine months ended September 30, 2014. Adjusted depletion, depreciation and amortization expense on a per barrel basis for the third quarter of 2015 increased 4% to \$13.95 per bbl from \$13.43 per bbl for the third quarter of 2014 and increased 16% from \$12.04 per bbl for the second quarter of 2015. The increase in the third quarter of 2015 reflected the impact of minor asset derecognitions.

The increase in depletion, depreciation and amortization expense for the three and nine months ended September 30, 2015 from the comparable periods primarily reflected the increase in sales volumes in 2015 and the impact of minor asset derecognitions.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

| (\$ millions, except per bbl amounts) | Three Months Ended | | | Nine Months Ended | |
|---------------------------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Expense | \$ 8 | \$ 7 | \$ 12 | \$ 23 | \$ 35 |
| \$/bbl ⁽¹⁾ | \$ 0.65 | \$ 0.82 | \$ 1.45 | \$ 0.70 | \$ 1.21 |

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

Asset retirement obligation accretion expense on a per barrel basis for the nine months ended September 30, 2015 decreased 42% to \$0.70 per bbl from \$1.21 per bbl for the nine months ended September 30, 2014. Asset retirement obligation accretion expense for the third quarter of 2015 decreased 55% to \$0.65 per bbl from \$1.45 per bbl for the third quarter of 2014 and decreased 21% from \$0.82 per bbl for the second quarter of 2015.

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

MIDSTREAM

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|------------------------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Revenue | \$ 33 | \$ 35 | \$ 30 | \$ 103 | \$ 91 |
| Production expense | 7 | 9 | 8 | 25 | 27 |
| Midstream cash flow | 26 | 26 | 22 | 78 | 64 |
| Depreciation | 3 | 3 | 2 | 9 | 7 |
| Equity loss (gain) from investment | 20 | (3) | 5 | 32 | 3 |
| Segment earnings before taxes | \$ 3 | \$ 26 | \$ 15 | \$ 37 | \$ 54 |

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.

The Company, along with APMC, have 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 the first quarter of 2015, the Company and APMC each provided an additional \$112 million of subordinated debt (year ended December 31, 2014 - \$113 million). 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 September 30, 2015, Redwater Partnership had borrowings of \$788 million under its secured \$3,500 million syndicated credit facility.

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

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

ADMINISTRATION EXPENSE

| (\$ millions, except per BOE amounts) | Three Months Ended | | | Nine Months Ended | |
|---------------------------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Expense | \$ 93 | \$ 100 | \$ 87 | \$ 297 | \$ 267 |
| \$/BOE ⁽¹⁾ | \$ 1.20 | \$ 1.35 | \$ 1.17 | \$ 1.28 | \$ 1.28 |

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

Administration expense on a per BOE basis for the nine months ended September 30, 2015 was comparable with the nine months ended September 30, 2014. Administration expense for the third quarter of 2015 increased 3% to \$1.20 per BOE from \$1.17 per BOE for the third quarter of 2014 and decreased 11% from \$1.35 per BOE for the second quarter of 2015. Administration expense per BOE decreased for the third quarter of 2015 from the second quarter of 2015 primarily due to lower staffing related costs and general corporate costs as well as the impact of higher sales volumes.

SHARE-BASED COMPENSATION

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|--------------------|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| (Recovery) Expense | \$ (87) | \$ (79) | \$ (122) | \$ (102) | \$ 210 |

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 \$102 million share-based compensation recovery for the nine months ended September 30, 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 nine months ended September 30, 2015, the Company recovered \$22 million of share-based compensation costs to property, plant and equipment in the Oil Sands Mining and Upgrading segment (September 30, 2014 – \$42 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

| (\$ millions, except per BOE amounts and interest rates) | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Expense, gross | \$ 142 | \$ 147 | \$ 135 | \$ 433 | \$ 386 |
| Less: capitalized interest | 64 | 62 | 56 | 184 | 147 |
| Expense, net | \$ 78 | \$ 85 | \$ 79 | \$ 249 | \$ 239 |
| \$/BOE ⁽¹⁾ | \$ 1.00 | \$ 1.16 | \$ 1.06 | \$ 1.08 | \$ 1.15 |
| Average effective interest rate | 3.8% | 3.8% | 3.9% | 3.9% | 4.0% |

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

Net interest and other financing expense on a per barrel basis for the nine months ended September 30, 2015 decreased 6% to \$1.08 per BOE from \$1.15 per BOE for the nine months ended September 30, 2014. Net interest and other financing expense on a per barrel basis for the third quarter of 2015 decreased 6% to \$1.00 per BOE from \$1.06 per BOE for the third quarter of 2014 and decreased 14% from \$1.16 per BOE for the second quarter of 2015. The decrease for the three and nine months ended September 30, 2015 from the comparable periods was primarily due to increased sales volumes, interest received on North Sea tax refunds, and the impact of higher capitalized interest.

Gross interest and other financing expense for the three and nine months ended September 30, 2015 increased from the comparable periods in 2014 primarily due to the impact of higher overall debt levels. Capitalized interest of \$184 million for the nine months ended September 30, 2015 was primarily related to the Horizon Phase 2/3 expansion.

The Company's average effective interest rate for the three and nine months ended September 30, 2015 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|--|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Crude oil and NGLs financial instruments | \$ (173) | \$ (91) | \$ – | \$ (381) | \$ – |
| Natural gas financial instruments | – | – | 21 | – | 33 |
| Foreign currency contracts | (90) | 22 | (17) | (207) | (47) |
| Realized (gain) loss | (263) | (69) | 4 | (588) | (14) |
| Crude oil and NGLs financial instruments | (12) | 205 | (70) | 205 | (24) |
| Natural gas financial instruments | – | – | (21) | – | – |
| Foreign currency contracts | (17) | 10 | (59) | (5) | (23) |
| Unrealized (gain) loss | (29) | 215 | (150) | 200 | (47) |
| Net (gain) loss | \$ (292) | \$ 146 | \$ (146) | \$ (388) | \$ (61) |

During the nine months ended September 30, 2015, net realized risk management gains were related to the settlement of crude oil and foreign currency contracts. The Company also recorded a net unrealized loss of \$200 million (\$147 million after-tax) on its risk management activities for the nine months ended September 30, 2015, including an unrealized gain of \$29 million (\$24 million after-tax) for the third quarter of 2015 (June 30, 2015 – unrealized loss of \$215 million; \$162 million after-tax; September 30, 2014 – unrealized gain of \$150 million; \$118 million after-tax).

Complete details related to outstanding derivative financial instruments at September 30, 2015 are disclosed in note 13 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Net realized (gain) loss | \$ (28) | \$ (11) | \$ (1) | \$ (92) | \$ 29 |
| Net unrealized loss (gain) ⁽¹⁾ | 351 | (76) | 185 | 688 | 150 |
| Net loss (gain) | \$ 323 | \$ (87) | \$ 184 | \$ 596 | \$ 179 |

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

The net realized foreign exchange gain for the nine months ended September 30, 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 nine months ended September 30, 2015 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2015 – unrealized gain of \$267 million, June 30, 2015 – unrealized loss of \$61 million, September 30, 2014 – unrealized gain of \$153 million; nine months ended September 30, 2015 – unrealized gain of \$520 million, September 30, 2014 – unrealized gain of \$144 million). The US/Canadian dollar exchange rate at September 30, 2015 was US\$0.7466 (June 30, 2015 – US\$0.8017, December 31, 2014 – US\$0.8620; September 30, 2014 – US\$0.8922).

INCOME TAXES

| (\$ millions, except income tax rates) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| North America ⁽¹⁾ | \$ 65 | \$ 79 | \$ 162 | \$ 152 | \$ 579 |
| North Sea | (16) | (19) | 14 | (99) | (45) |
| Offshore Africa | 5 | 5 | 21 | 12 | 35 |
| PRT recovery – North Sea | (61) | (72) | (114) | (187) | (187) |
| Other taxes | 2 | 4 | 6 | 9 | 18 |
| Current income tax (recovery) expense | (5) | (3) | 89 | (113) | 400 |
| Deferred income tax expense | 8 | 498 | 158 | 217 | 427 |
| Deferred PRT expense – North Sea | 10 | 30 | 50 | 47 | 127 |
| Deferred income tax expense | 18 | 528 | 208 | 264 | 554 |
| Income tax rate and other legislative changes ^{(2) (3)} | \$ 13 | \$ 525 | \$ 297 | \$ 151 | \$ 954 |
| | – | (579) | – | (351) | – |
| | \$ 13 | \$ (54) | \$ 297 | \$ (200) | \$ 954 |
| Effective income tax rate on adjusted net earnings from operations ⁽⁴⁾ | 28.0% | 17.0% | 24.7% | 10.3% | 24.4% |

(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 third quarter of 2015 and the comparative quarters reflects the impact of abandonment expenditures on the Murchison platform.

The effective income tax rate for the three and nine months ended September 30, 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.

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 2015, based on forward commodity prices and the current availability of tax pools, the Company now expects to incur current income tax expense of \$150 million to \$200 million in Canada and recoveries of \$285 million to \$335 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES ⁽¹⁾

| (\$ millions) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Exploration and Evaluation | | | | | |
| Net expenditures ^{(2) (3)} | \$ 5 | \$ 29 | \$ 92 | \$ 80 | \$ 1,093 |
| Property, Plant and Equipment | | | | | |
| Net property acquisitions ^{(2) (3)} | (70) | 51 | 79 | (8) | 2,821 |
| Well drilling, completion and equipping | 237 | 199 | 498 | 728 | 1,580 |
| Production and related facilities | 191 | 249 | 504 | 754 | 1,348 |
| Capitalized interest and other ⁽⁴⁾ | 23 | 27 | 34 | 76 | 78 |
| Net expenditures | 381 | 526 | 1,115 | 1,550 | 5,827 |
| Total Exploration and Production | 386 | 555 | 1,207 | 1,630 | 6,920 |
| Oil Sands Mining and Upgrading | | | | | |
| Horizon Phase 2/3 construction costs | 668 | 535 | 670 | 1,609 | 1,763 |
| Sustaining capital | 64 | 94 | 122 | 246 | 269 |
| Turnaround costs | 3 | 6 | 15 | 13 | 21 |
| Capitalized interest and other ⁽⁴⁾ | 42 | 43 | 38 | 156 | 195 |
| Total Oil Sands Mining and Upgrading | 777 | 678 | 845 | 2,024 | 2,248 |
| Midstream | 2 | 1 | 27 | 6 | 78 |
| Abandonments ⁽⁴⁾ | 65 | 56 | 82 | 265 | 245 |
| Head office | 10 | 7 | 14 | 24 | 33 |
| Total net capital expenditures | \$ 1,240 | \$ 1,297 | \$ 2,175 | \$ 3,949 | \$ 9,524 |
| By segment | | | | | |
| North America ^{(2) (3)} | \$ 199 | \$ 307 | \$ 997 | \$ 1,007 | \$ 6,471 |
| North Sea | 41 | 93 | 100 | 196 | 295 |
| Offshore Africa | 146 | 155 | 110 | 427 | 154 |
| Oil Sands Mining and Upgrading | 777 | 678 | 845 | 2,024 | 2,248 |
| Midstream | 2 | 1 | 27 | 6 | 78 |
| Abandonments ⁽⁵⁾ | 65 | 56 | 82 | 265 | 245 |
| Head office | 10 | 7 | 14 | 24 | 33 |
| Total | \$ 1,240 | \$ 1,297 | \$ 2,175 | \$ 3,949 | \$ 9,524 |

(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 disposition 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.

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

Previously in 2015, the Company reduced its annual capital expenditure guidance by approximately \$3,100 million. In November 2015, the Company further exercised its capital flexibility and announced that it would reduce annual capital spending guidance by an additional \$65 million.

Net capital expenditures for the nine months ended September 30, 2015 were \$3,949 million compared with \$9,524 million for the nine months ended September 30, 2014. Net capital expenditures for the third quarter of 2015 were \$1,240 million compared with \$2,175 million for the third quarter of 2014 and \$1,297 million for the second quarter of 2015. The capital expenditures for the three and nine months ended September 30, 2015 reflected the Company's previously announced reduction in its capital program, as well as its capital allocation strategy, including the planned drilling activities in Offshore Africa.

Drilling Activity

| (number of wells) | Three Months Ended | | | Nine Months Ended | |
|---|--------------------|----------------|----------------|-------------------|----------------|
| | Sep 30 2015 | Jun 30 2015 | Sep 30 2014 | Sep 30 2015 | Sep 30 2014 |
| Net successful natural gas wells | 4 | 2 | 21 | 15 | 59 |
| Net successful crude oil wells ⁽¹⁾ | 66 | 5 | 273 | 113 | 698 |
| Dry wells | 4 | – | 6 | 6 | 11 |
| Stratigraphic test / service wells | 1 | 6 | 11 | 93 | 363 |
| Total | 75 | 13 | 311 | 227 | 1,131 |
| Success rate (excluding stratigraphic test / service wells) | 95% | 100% | 98% | 96% | 99% |

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 28% of the total capital expenditures for the nine months ended September 30, 2015 compared with approximately 70% for the nine months ended September 30, 2014.

During the third quarter of 2015, the Company targeted 4 net natural gas wells, including 2 wells in Northwest Alberta, 1 well in Northeast British Columbia and 1 well in Northern Plains. The Company also targeted 67 net primary heavy crude oil wells in the Company's Northern Plains region.

Overall thermal oil production for the third quarter of 2015 averaged approximately 133,200 bbl/d compared with approximately 115,300 bbl/d for the third quarter of 2014 and approximately 105,000 bbl/d for the second quarter of 2015. Production volumes in the third quarter of 2015 reflected the reinstatement of production after the forest fires in Northeastern Alberta, together with the cyclic nature of thermal oil production at Primrose.

Development of the tertiary recovery conversion projects at Pelican Lake continued. Pelican Lake production averaged approximately 50,900 bbl/d for the third quarter of 2015 compared with 51,900 bbl/d for the third quarter of 2014 and 52,000 bbl/d for the second quarter of 2015.

In order to expand its pipeline infrastructure, the Company is participating in the expansion of the Cold Lake pipeline system. Initial pipeline commissioning activities commenced in the first quarter of 2015 with the final phases of the project expected to continue for approximately three years.

Oil Sands Mining and Upgrading

Phase 2/3 expansion activity in the third quarter of 2015 continued to focused 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.

Targeted annual capital spending in 2015 was further revised from \$2,200 million to \$2,150 million during the second quarter of 2015 through targeted cost efficiencies, while maintaining planned expansion activities.

North Sea

During 2015, the Company completed one injection well and no further development activities are planned. 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 wells, adding net production volumes of approximately 5,300 bbl/d to date. The infill drilling program is currently tracking to below its original sanction costs for the 10 gross well program (5.9 net well program).

During 2015, at the Baobab field, Côte d'Ivoire, the Company drilled 3 gross wells, adding net production volumes of approximately 6,300 bbl/d to date. Production from the fourth gross well is targeted to come on stream in the fourth quarter of 2015. The drilling program is currently tracking to below its original sanction costs for the 6 gross well drilling program (3.4 net well program).

In Block CI-514, the Company has a 36% non-operated interest. In the second quarter of 2014, the operator completed drilling the first exploratory well and encountered the presence of light oil. As a follow-up, in April 2015, a second exploratory well was drilled to evaluate the potential of the initial well. The second exploratory well has been plugged and abandoned, and the results will be evaluated and integrated into the Company's understanding of the block.

LIQUIDITY AND CAPITAL RESOURCES

| (\$ millions, except ratios) | Sep 30 2015 | Jun 30 2015 | Dec 31 2014 | Sep 30 2014 |
|--|----------------|----------------|----------------|----------------|
| Working capital (deficit) ⁽¹⁾ | \$ 309 | \$ 261 | \$ (673) | \$ (915) |
| Long-term debt ^{(2) (3)} | \$ 16,510 | \$ 15,983 | \$ 14,002 | \$ 13,685 |
| Share capital | \$ 4,533 | \$ 4,532 | \$ 4,432 | \$ 4,388 |
| Retained earnings | 22,885 | 23,248 | 24,408 | 23,499 |
| Accumulated other comprehensive income (loss) | 67 | (7) | 51 | 47 |
| Shareholders' equity | \$ 27,485 | \$ 27,773 | \$ 28,891 | \$ 27,934 |
| Debt to book capitalization ^{(3) (4)} | 38% | 37% | 33% | 33% |
| Debt to market capitalization ^{(3) (5)} | 37% | 30% | 26% | 22% |
| After-tax return on average common shareholders' equity ⁽⁶⁾ | 2% | 6% | 14% | 12% |
| After-tax return on average capital employed ^{(3) (7)} | 2% | 4% | 10% | 9% |

(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 for the twelve month trailing period; as a percentage of average common shareholders' equity for the period.

(7) Calculated as net earnings 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 September 30, 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 is dependent upon maintaining an investment grade debt rating and the condition of capital and credit markets. The Company continues to believe that its internally generated cash flow from operations supported by the implementation of its ongoing hedge policy, 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:
 - Subsequent to September 30, 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 September 30, 2015;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages. 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; 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.

As at September 30, 2015, the Company had in place bank credit facilities of \$7,480 million, of which \$3,440 million, net of commercial paper issuances of \$669 million, was available for general corporate purposes.

At September 30, 2015, the Company had long-term debt with a carrying amount of \$1,004 million maturing over the next 12 months (US\$500 million of three-month LIBOR plus 0.375% due March 2016 and US\$250 million of 6.00% 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.

Long-term debt was \$16,510 million at September 30, 2015, resulting in a debt to book capitalization ratio of 38% (December 31, 2014 – 33%; September 30, 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. The Company has hedged a portion of its production for 2015 at prices that protect investment returns to support ongoing balance sheet strength and the completion of its capital expenditure programs. Further details related to the Company's long-term debt at September 30, 2015 are discussed in note 6 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. As at November 3, 2015, 50,000 bbl/d of currently forecasted crude oil volumes were hedged using price collars for the remainder of 2015. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2015 are discussed in note 13 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2015, there were 1,094,408,000 common shares outstanding (December 31, 2014 – 1,091,837,000 common shares) and 67,308,000 stock options outstanding. As at November 3, 2015, the Company had 1,094,450,000 common shares outstanding and 67,118,000 stock options outstanding.

On March 4, 2015, the Board of Directors approved an increase in the annual dividend to \$0.92 per common share, (previous annual dividend rate of \$0.90 per common share), beginning with the quarterly dividend payable on April 1, 2015, at \$0.23 per common share. 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 nine months ended September 30, 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 September 30, 2015:

| (\$ millions) | Remaining | | | | | |
|---|-----------|----------|----------|----------|----------|------------|
| | 2015 | 2016 | 2017 | 2018 | 2019 | Thereafter |
| Product transportation and pipeline | \$ 110 | \$ 381 | \$ 337 | \$ 295 | \$ 256 | \$ 1,542 |
| Offshore equipment operating leases and offshore drilling | \$ 119 | \$ 174 | \$ 90 | \$ 68 | \$ 22 | \$ – |
| Long-term debt ^{(1) (3)} | \$ 669 | \$ 1,005 | \$ 2,472 | \$ 2,842 | \$ 1,369 | \$ 8,229 |
| Interest and other financing expense ⁽²⁾ | \$ 122 | \$ 633 | \$ 551 | \$ 467 | \$ 427 | \$ 4,858 |
| Office leases | \$ 10 | \$ 41 | \$ 42 | \$ 43 | \$ 43 | \$ 239 |
| Other | \$ 54 | \$ 131 | \$ 65 | \$ 36 | \$ – | \$ – |

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

(2) 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 September 30, 2015.

(3) At September 30, 2015, the Company had US\$500 million of three-month LIBOR plus 0.375% due March 2016 and US\$250 million of 6.00% 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.

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.

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.