Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2017 AND 2016

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, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the construction and future operations of the North West Redwater bitumen upgrader and refinery, and construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets, including the interests in AOSP as well as additional working interests in certain other producing and non-producing oil and gas properties (the "other assets"), acquired by the Company on May 31, 2017; 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 six months ended June 30, 2017 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2016.

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 June 30, 2017 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as adjusted net earnings (loss) from operations, funds flow from operations (previously referred to as cash flow from operations), and adjusted cash production costs. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss) and cash flows from operating activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measures adjusted net earnings (loss) from operations and funds flow from operations are reconciled to net earnings (loss), as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure funds flow from operations is also reconciled to cash flows from operating activities in this section. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights – Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" or "gross" basis, and realized prices are net of blending and feedstock 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 six months ended June 30, 2017 in relation to the comparable periods in 2016 and the first quarter of 2017. 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, 2016, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated August 2, 2017.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Jun 30 2017**	Mar 31 2017	Jun 30 2016	Six Months Ended **Jun 30 2017**	Jun 30 2016
Product sales	**$ 3,927**	$ 3,872	$ 2,686	**$ 7,799**	$ 4,949
Net earnings (loss)	**$ 1,072**	$ 245	$ (339)	**$ 1,317**	$ (444)
Per common share – basic	**$ 0.93**	$ 0.22	$ (0.31)	**$ 1.16**	$ (0.41)
– diluted	**$ 0.93**	$ 0.22	$ (0.31)	**$ 1.16**	$ (0.41)
Adjusted net earnings (loss) from operations (1)	**$ 332**	$ 277	$ (210)	**$ 609**	$ (753)
Per common share – basic	**$ 0.29**	$ 0.25	$ (0.19)	**$ 0.54**	$ (0.69)
– diluted	**$ 0.29**	$ 0.25	$ (0.19)	**$ 0.54**	$ (0.69)
Funds flow from operations (2)	**$ 1,726**	$ 1,639	$ 938	**$ 3,365**	$ 1,595
Per common share – basic	**$ 1.50**	$ 1.47	$ 0.85	**$ 2.97**	$ 1.45
– diluted	**$ 1.49**	$ 1.46	$ 0.85	**$ 2.95**	$ 1.45
Net capital expenditures	**$ 13,046**	$ 846	$ 1,158	**$ 13,892**	$ 2,198

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

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

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

Adjusted Net Earnings (Loss) from Operations

($ millions)	Three Months Ended Jun 30 2017	Mar 31 2017	Jun 30 2016	Six Months Ended Jun 30 2017	Jun 30 2016
Net earnings (loss) as reported	**$ 1,072**	$ 245	$ (339)	**$ 1,317**	$ (444)
Share-based compensation, net of tax (1)	**(104)**	27	122	**(77)**	239
Unrealized risk management loss (gain), net of tax (2)	**2**	(31)	(46)	**(29)**	17
Unrealized foreign exchange (gain) loss, net of tax (3)	**(355)**	(60)	40	**(415)**	(294)
(Gain) loss from investments, net of tax (4)(5)	**(27)**	96	—	**69**	(147)
Gain on acquisition and disposition of properties, net of tax (6)	**(256)**	—	—	**(256)**	(23)
Derecognition of exploration and evaluation assets, net of tax (7)	**—**	—	13	**—**	13
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	—	—	**—**	(114)
Adjusted net earnings (loss) from operations	**$ 332**	$ 277	$ (210)	**$ 609**	$ (753)

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

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

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

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

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

(6) During the second quarter of 2017, the Company recorded a before and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment. During the first quarter of 2016, the Company recorded a pre-tax gain of $32 million ($23 million after-tax) on the disposition of certain exploration and evaluation assets.

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

(8) During the first quarter of 2016, the UK government enacted tax rate reductions relating to Petroleum Revenue Tax ("PRT"), resulting in a decrease in the Company's net deferred income tax liability of $114 million.

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

($ millions)	Three Months Ended Jun 30 2017	Mar 31 2017	Jun 30 2016	Six Months Ended Jun 30 2017	Jun 30 2016
Net earnings (loss)	***$ 1,072***	*$ 245*	*$ (339)*	***$ 1,317***	*$ (444)*
Non-cash items:					
Depletion, depreciation and amortization	***1,210***	*1,299*	*1,174*	***2,509***	*2,393*
Share-based compensation	***(104)***	*27*	*122*	***(77)***	*239*
Asset retirement obligation accretion	***39***	*36*	*35*	***75***	*71*
Unrealized risk management (gain) loss	***(6)***	*(40)*	*(52)*	***(46)***	*22*
Unrealized foreign exchange (gain) loss	***(355)***	*(60)*	*40*	***(415)***	*(294)*
(Gain) loss from investments	***(27)***	*96*	*—*	***69***	*(147)*
Deferred income tax expense (recovery)	***162***	*36*	*(42)*	***198***	*(213)*
Gain on acquisition and disposition of properties	***(265)***	*—*	*—*	***(265)***	*(32)*
Funds flow from operations	***$ 1,726***	*$ 1,639*	*$ 938*	***$ 3,365***	*$ 1,595*

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

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

($ millions)	Three Months Ended Jun 30 2017	Mar 31 2017	Jun 30 2016	Six Months Ended Jun 30 2017	Jun 30 2016
Cash flows from operating activities	***$ 1,631***	*$ 1,671*	*$ 717*	***$ 3,302***	*$ 1,298*
Net change in non-cash working capital	***(39)***	*(51)*	*190*	***(90)***	*211*
Abandonment expenditures	***105***	*41*	*36*	***146***	*110*
Other	***29***	*(22)*	*(5)*	***7***	*(24)*
Funds flow from operations	***$ 1,726***	*$ 1,639*	*$ 938*	***$ 3,365***	*$ 1,595*

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

Net earnings for the six months ended June 30, 2017 were $1,317 million compared with a net loss of $444 million for the six months ended June 30, 2016. Net earnings for the six months ended June 30, 2017 included net after-tax income of $708 million compared with net after-tax income of $309 million for the six months ended June 30, 2016 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on acquisition and disposition of properties, the derecognition of exploration and evaluation assets and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2017 were $609 million compared with an adjusted net loss of $753 million for the six months ended June 30, 2016.

Net earnings for the second quarter of 2017 were $1,072 million compared with a net loss of $339 million for the second quarter of 2016 and net earnings of $245 million for the first quarter of 2017. Net earnings for the second quarter of 2017 included net after-tax income of $740 million compared with net after-tax expenses of $129 million for the second quarter of 2016 and net after-tax expenses of $32 million for the first quarter of 2017 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, (gain) loss from investments, gain on acquisition and disposition of properties and the derecognition of exploration and evaluation assets. Excluding these items, adjusted net earnings from operations for the second quarter of 2017 were $332 million compared with an adjusted net loss of $210 million for the second quarter of 2016 and adjusted net earnings of $277 million for the first quarter of 2017.

The increase in adjusted net earnings for the three and six months ended June 30, 2017 from the three and six months ended June 30, 2016 was primarily due to:

- record high SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with both the acquisition of AOSP and Phase 2B sales volumes at Horizon;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- higher realized risk management gains;

partially offset by:

- lower sales volumes in the Offshore Africa segment; and
- higher interest and financing expense.

The increase in adjusted net earnings for the second quarter of 2017 from the first quarter of 2017 was primarily due to:

- record high SCO sales volumes in the Oil Sands Mining and Upgrading segment, due to volumes associated with the acquisition of AOSP;

partially offset by:

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

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

Funds flow from operations for the six months ended June 30, 2017 was $3,365 million compared with $1,595 million for the six months ended June 30, 2016. Funds flow from operations for the second quarter of 2017 was $1,726 million compared with $938 million for the second quarter of 2016 and $1,639 million for the first quarter of 2017. The fluctuations in funds flow from operations from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (loss), as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the second quarter of 2017 increased 16% to 913,171 BOE/d from 783,988 BOE/d for the second quarter of 2016 and increased 4% from 876,907 BOE/d for the first quarter of 2017.

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)		**Jun 30 2017**		Mar 31 2017		Dec 31 2016		Sep 30 2016
Product sales	**$**	**3,927**	$	3,872	$	3,672	$	2,477
Net earnings (loss)	**$**	**1,072**	$	245	$	566	$	(326)
Net earnings (loss) per common share								
– basic	**$**	**0.93**	$	0.22	$	0.51	$	(0.29)
– diluted	**$**	**0.93**	$	0.22	$	0.51	$	(0.29)
($ millions, except per common share amounts)		Jun 30 2016		Mar 31 2016		Dec 31 2015		Sep 30 2015
Product sales	$	2,686	$	2,263	$	2,963	$	3,316
Net earnings (loss)	$	(339)	$	(105)	$	131	$	(111)
Net earnings (loss) per common share								
– basic	$	(0.31)	$	(0.10)	$	0.12	$	(0.10)
– diluted	$	(0.31)	$	(0.10)	$	0.12	$	(0.10)

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

- **Crude oil pricing** – The impact of shale oil production in North America, fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America and the impact of the differential between WTI and Brent benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company’s drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, the impact of turnarounds at Horizon, and the impact of the drilling program in Côte d’Ivoire in Offshore Africa. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, an outage at a third party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds at Horizon and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark - to - market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impacted the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense include statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gain on acquisition and disposition of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, disposition of properties in the various periods and fair value changes in the investments in PrairieSky and Inter Pipeline shares.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended Jun 30 2017	Three Months Ended Mar 31 2017	Three Months Ended Jun 30 2016	Six Months Ended Jun 30 2017	Six Months Ended Jun 30 2016
WTI benchmark price (US$/bbl)	**$ 48.29**	$ 51.86	$ 45.60	**$ 50.07**	$ 39.56
Dated Brent benchmark price (US$/bbl)	**$ 50.24**	$ 54.05	$ 45.80	**$ 52.14**	$ 39.86
WCS blend differential from WTI (US$/bbl)	**$ 11.11**	$ 14.58	$ 13.31	**$ 12.84**	$ 13.77
SCO price (US$/bbl)	**$ 49.83**	$ 51.45	$ 47.39	**$ 50.63**	$ 40.58
Condensate benchmark price (US$/bbl)	**$ 48.44**	$ 52.21	$ 44.10	**$ 50.31**	$ 39.28
NYMEX benchmark price (US$/MMBtu)	**$ 3.18**	$ 3.31	$ 1.95	**$ 3.25**	$ 2.00
AECO benchmark price (C$/GJ)	**$ 2.63**	$ 2.79	$ 1.18	**$ 2.71**	$ 1.59
US/Canadian dollar average exchange rate (US$)	**$ 0.7436**	$ 0.7554	$ 0.7761	**$ 0.7495**	$ 0.7518

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Dated Brent ("Brent") indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. For the three and six months ended June 30, 2017, realized prices continued to be supported by the weaker Canadian dollar, as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$50.07 per bbl for the six months ended June 30, 2017, an increase of 27% from US$39.56 per bbl for the six months ended June 30, 2016. WTI averaged US$48.29 per bbl for the second quarter of 2017, an increase of 6% from US$45.60 per bbl for the second quarter of 2016, and a decrease of 7% from US$51.86 per bbl for the first quarter of 2017.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$52.14 per bbl for the six months ended June 30, 2017, an increase of 31% from US$39.86 per bbl for the six months ended June 30, 2016. Brent averaged US$50.24 per bbl for the second quarter of 2017, an increase of 10% from US$45.80 per bbl for the second quarter of 2016, and a decrease of 7% from US$54.05 per bbl for the first quarter of 2017.

WTI and Brent pricing for the three and six months ended June 30, 2017 continued to reflect volatility in supply and demand factors and geopolitical events. Benchmark pricing continued to reflect the OPEC decision in November 2016 to implement a production cut effective January 1, 2017 followed by additional production cuts by certain non-OPEC countries. The decrease in benchmark pricing for the second quarter of 2017 from the first quarter of 2017 reflected increased production in certain non-OPEC countries.

The WCS Heavy Differential averaged US$12.84 per bbl for the six months ended June 30, 2017, a decrease of 7% from US$13.77 per bbl for the six months ended June 30, 2016. The WCS Heavy Differential averaged US$11.11 per bbl for the second quarter of 2017, a decrease of 17% from US$13.31 per bbl for the second quarter of 2016, and a decrease of 24% from US$14.58 per bbl for the first quarter of 2017. The WCS Heavy Differential reflects US Gulf Coast pricing, adjusted for transportation costs. The narrowing of the differential for the second quarter of 2017 compared with the first quarter of 2017 reflected seasonality.

The SCO price averaged US$50.63 per bbl for the six months ended June 30, 2017, an increase of 25% from US$40.58 per bbl for the six months ended June 30, 2016. The SCO price averaged US$49.83 per bbl for the second quarter of 2017, an increase of 5% from US$47.39 per bbl for the second quarter of 2016, and a decrease of 3% from US$51.45 per bbl for the first quarter of 2017. The fluctuations in SCO pricing for the three and six months ended June 30, 2017 from the comparable periods were primarily due to changes in WTI benchmark pricing and the impact of unplanned third party oil sands production outages.

NYMEX natural gas prices averaged US$3.25 per MMBtu for the six months ended June 30, 2017, an increase of 63% from US$2.00 per MMBtu for the six months ended June 30, 2016. NYMEX natural gas prices averaged US$3.18 per MMBtu for the second quarter of 2017, an increase of 63% from US$1.95 per MMBtu for the second quarter of 2016, and a decrease of 4% from US$3.31 per MMBtu for the first quarter of 2017.

AECO natural gas prices averaged $2.71 per GJ for the six months ended June 30, 2017, an increase of 70% from $1.59 per GJ for the six months ended June 30, 2016. AECO natural gas prices averaged $2.63 per GJ for the second quarter of 2017, an increase of 123% from $1.18 per GJ for the second quarter of 2016, and a decrease of 6% from $2.79 per GJ for the first quarter of 2017.

The increase in natural gas prices for the three and six months ended June 30, 2017 compared with the three and six months ended June 30, 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016, resulting in lower US natural gas production. Additionally, pricing reflected colder weather in the 2016/2017 winter season as compared with the previous year.

The decrease in natural gas prices in the second quarter of 2017 compared with the first quarter of 2017 reflected seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**332,802**	359,964	328,681	**346,308**	349,334
Oil Sands Mining and Upgrading – Horizon (1)	**190,837**	192,491	119,511	**191,660**	123,710
Oil Sands Mining and Upgrading – AOSP	**66,704**	—	—	**33,536**	—
North Sea	**26,304**	23,042	23,360	**24,682**	23,338
Offshore Africa	**20,480**	22,616	30,858	**21,542**	28,286
	637,127	598,113	502,410	**617,728**	524,668
Natural gas (MMcf/d)					
North America	**1,603**	1,613	1,620	**1,607**	1,672
North Sea	**37**	37	30	**37**	29
Offshore Africa	**16**	23	39	**20**	37
	1,656	1,673	1,689	**1,664**	1,738
Total barrels of oil equivalent (BOE/d)	**913,171**	876,907	783,988	**895,139**	814,259
Product mix					
Light and medium crude oil and NGLs	**15%**	15%	18%	**15%**	17%
Pelican Lake heavy crude oil	**5%**	5%	6%	**5%**	6%
Primary heavy crude oil	**10%**	11%	13%	**10%**	13%
Bitumen (thermal oil)	**12%**	15%	12%	**13%**	13%
Synthetic crude oil	**28%**	22%	15%	**26%**	15%
Natural gas	**30%**	32%	36%	**31%**	36%
Percentage of gross revenue (1) (2) (excluding Midstream revenue)					
Crude oil and NGLs	**88%**	86%	90%	**87%**	85%
Natural gas	**12%**	14%	10%	**13%**	15%

(1) Second quarter 2017 SCO production before royalties excludes 438 bbl/d of SCO consumed internally as diesel (first quarter 2017 – 428 bbl/d; second quarter 2016 – 2,227 bbl/d; six months ended June 30, 2017 - 433 bbl/d; six months ended June 30, 2016 - 2,394 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**291,716**	313,070	292,666	**302,334**	311,989
Oil Sands Mining and Upgrading – Horizon	**187,315**	189,182	118,613	**188,243**	123,541
Oil Sands Mining and Upgrading – AOSP	**64,308**	—	—	**32,332**	—
North Sea	**26,246**	23,001	23,279	**24,632**	23,272
Offshore Africa	**19,231**	21,702	29,658	**20,461**	27,118
	588,816	546,955	464,216	**568,002**	485,920
Natural gas (MMcf/d)					
North America	**1,528**	1,503	1,604	**1,515**	1,630
North Sea	**37**	37	30	**37**	29
Offshore Africa	**15**	21	37	**18**	35
	1,580	1,561	1,671	**1,570**	1,694
Total barrels of oil equivalent (BOE/d)	**852,170**	807,045	742,785	**829,733**	768,310

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 six months ended June 30, 2017 increased 18% to 617,728 bbl/d from 524,668 bbl/d for the six months ended June 30, 2016. Crude oil and NGLs production for the second quarter of 2017 of 637,127 bbl/d increased by 27% from 502,410 bbl/d for the second quarter of 2016, and increased by 7% from 598,113 bbl/d in the first quarter of 2017. The increase in crude oil and NGLs production for the three and six months ended June 30, 2017 from the comparable periods in 2016 was primarily due to increased volumes in the Oil Sands Mining and Upgrading segment due to Horizon Phase 2B as well as the acquisition of AOSP on May 31, 2017. The increase in crude oil and NGLs production for the second quarter of 2017 from the first quarter of 2017 primarily reflected added production volumes in the Oil Sands Mining and Upgrading segment associated with the acquisition of AOSP.

Second quarter 2017 crude oil and NGLs production was at the high end of the Company's previously issued revised guidance of 606,000 to 638,000 bbl/d of crude oil and NGLs, which reflected the acquisition of AOSP and other assets. Third quarter 2017 production guidance is targeted to average between 740,000 and 778,000 bbl/d of crude oil and NGLs. Annual production guidance for 2017 is now targeted to average between 663,000 and 717,000 bbl/d.

Natural gas production for the six months ended June 30, 2017 decreased 4% to 1,664 MMcf/d from 1,738 MMcf/d for the six months ended June 30, 2016. Natural gas production for the second quarter of 2017 averaged 1,656 MMcf/d, slightly lower than 1,689 MMcf/d for the second quarter of 2016 and 1,673 MMcf/d for the first quarter of 2017. Natural gas production for the three and six months ended June 30, 2017 decreased from the comparable periods primarily due to the impact of ongoing reliability issues at a third party facility.

Second quarter natural gas production was slightly below the previously issued guidance of 1,675 to 1,730 MMcf/d as a result of the impact of ongoing reliability issues at a third party facility. Third quarter 2017 natural gas production guidance is targeted to average between 1,650 and 1,710 MMcf/d. Annual production guidance for 2017 is now targeted to average between 1,655 and 1,705 MMcf/d.

North America - Exploration and Production

North America crude oil and NGLs production for the six months ended June 30, 2017 averaged 346,308 bbl/d, comparable with 349,334 bbl/d for the six months ended June 30, 2016. North America crude oil and NGLs production for the second quarter of 2017 averaged 332,802 bbl/d, comparable with 328,681 bbl/d for the second quarter of 2016, and a decrease of 8% from 359,964 bbl/d for the first quarter of 2017. The decrease in production for the second quarter of 2017 from the first quarter of 2017 primarily reflected the successful completion of planned turnarounds at the Primrose and Kirby South plants during the second quarter of 2017, partially offset by the impact of added production volumes as a result of the acquisition of the other assets on May 31, 2017. Second quarter 2017 production of crude oil and NGLs was within the Company's previously issued revised guidance of 323,000 to 337,000 bbl/d, which reflected the acquisitions effective May 31, 2017. Third quarter 2017 production guidance is targeted to average between 358,000 and 372,000 bbl/d of crude oil and NGLs. Annual production guidance for 2017 is now targeted to average between 348,000 and 368,000 bbl/d.

Natural gas production for the six months ended June 30, 2017 decreased 4% to average 1,607 MMcf/d from 1,672 MMcf/d for the six months ended June 30, 2016. Natural gas production for the second quarter of 2017 averaged 1,603 MMcf/d, slightly lower than 1,620 MMcf/d for the second quarter of 2016 and 1,613 MMcf/d in the first quarter of 2017. Natural gas production for the three and six months ended June 30, 2017 reflected the impact of ongoing reliability issues at a third party facility. Average production from the facility during the second quarter of 2017 was approximately 52 MMcf/d, compared with 100 MMcf/d during the first quarter of 2017, and 36 MMcf/d lower than expected for the second quarter of 2017.

Horizon

Horizon SCO production for the six months ended June 30, 2017 of 191,660 bbl/d increased 55% from 123,710 bbl/d for the six months ended June 30, 2016. Horizon SCO production for the second quarter of 2017 increased 60% to average 190,837 bbl/d compared with 119,511 bbl/d for the second quarter of 2016 and was comparable with 192,491 bbl/d for the first quarter of 2017. The increase in production for the three and six months ended June 30, 2017 from the comparable periods in 2016 primarily reflected new Phase 2B production at Horizon, the utilization of Phase 3 infrastructure and continued high reliability in the mining and upgrading operations.

Second quarter 2017 production of Horizon SCO was above the Company’s previously issued guidance of 180,000 to 188,000 bbl/d. Third quarter 2017 production guidance is targeted to average between 148,000 and 160,000 bbl/d and reflects the impact of a planned turnaround targeted to commence September 2017.

Athabasca Oil Sands Project

AOSP SCO production for the second quarter of 2017 averaged 66,704 bbl/d, reflecting the Company's 70% interest in the project. AOSP SCO production for the second quarter of 2017 was above the previously issued guidance of 57,000 to 63,000 bbl/d. June production reflected the high reliability and efficiency of AOSP operations, averaging 202,300 bbl/d.

Third quarter 2017 production guidance is targeted to average between 193,000 and 201,000 bbl/d. Annual production guidance for 2017 is now targeted to average between 102,000 and 116,000 bbl/d.

North Sea

North Sea crude oil production for the six months ended June 30, 2017 increased 6% to 24,682 bbl/d from 23,338 bbl/d for the six months ended June 30, 2016. North Sea crude oil production for the second quarter of 2017 increased 13% to 26,304 bbl/d from 23,360 bbl/d for the second quarter of 2016 and increased 14% from 23,042 bbl/d for the first quarter of 2017. The increase in production for the three and six months ended June 30, 2017 from comparable periods was due to new wells at Ninian and successful production optimization.

Offshore Africa

Offshore Africa crude oil production for the six months ended June 30, 2017 decreased 24% to 21,542 bbl/d from 28,286 bbl/d for the six months ended June 30, 2016. Offshore Africa crude oil production for the second quarter of 2017 decreased 34% to 20,480 bbl/d from 30,858 bbl/d for the second quarter of 2016, and decreased 9% from 22,616 bbl/d for the first quarter of 2017. The decrease in production for the three and six months ended June 30, 2017 from comparable periods reflected the successful completion of the turnaround at Espoir during the second quarter of 2017.

The Company completed a planned turnaround at Baobab during the third quarter of 2017, which has been reflected in third quarter production guidance.

INTERNATIONAL GUIDANCE

Second quarter international crude oil production was within the Company's previously issued guidance of 46,000 to 50,000 bbl/d. Third quarter 2017 production guidance is targeted to average between 41,000 and 45,000 bbl/d of crude oil.

International Crude Oil Inventory Volumes

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

(bbl)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016
North Sea	**528,705**	339,457	1,244,684
Offshore Africa	**1,510,446**	1,102,137	1,248,197
	2,039,151	1,441,594	2,492,881

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 47.12**	$ 47.05	$ 39.98	**$ 47.08**	$ 31.40
Transportation	**3.06**	2.54	2.81	**2.78**	2.63
Realized sales price, net of transportation	**44.06**	44.51	37.17	**44.30**	28.77
Royalties	**4.83**	4.89	3.59	**4.86**	2.72
Production expense	**15.51**	14.37	14.31	**14.92**	14.12
Netback	**$ 23.72**	$ 25.25	$ 19.27	**$ 24.52**	$ 11.93
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.97**	$ 3.25	$ 1.50	**$ 3.11**	$ 1.88
Transportation	**0.34**	0.43	0.35	**0.39**	0.31
Realized sales price, net of transportation	**2.63**	2.82	1.15	**2.72**	1.57
Royalties	**0.12**	0.19	0.02	**0.15**	0.05
Production expense	**1.25**	1.28	1.22	**1.26**	1.23
Netback	**$ 1.26**	$ 1.35	$ (0.09)	**$ 1.31**	$ 0.29
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 33.94**	$ 35.98	$ 27.28	**$ 34.99**	$ 23.21
Transportation	**2.67**	2.57	2.61	**2.62**	2.40
Realized sales price, net of transportation	**31.27**	33.41	24.67	**32.37**	20.81
Royalties	**3.09**	3.38	2.13	**3.24**	1.70
Production expense	**12.11**	11.67	11.38	**11.89**	11.28
Netback	**$ 16.07**	$ 18.36	$ 11.16	**$ 17.24**	$ 7.83

(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			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 44.78**	$ 44.17	$ 37.59	**$ 44.47**	$ 28.78
North Sea	**$ 64.37**	$ 70.03	$ 54.60	**$ 67.49**	$ 48.90
Offshore Africa	**$ 69.93**	$ 61.95	$ 54.62	**$ 65.25**	$ 50.61
Company average	**$ 47.12**	$ 47.05	$ 39.98	**$ 47.08**	$ 31.40
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.84**	$ 3.08	$ 1.30	**$ 2.96**	$ 1.68
North Sea	**$ 6.89**	$ 8.68	$ 6.83	**$ 7.78**	$ 6.92
Offshore Africa	**$ 6.84**	$ 6.23	$ 6.01	**$ 6.49**	$ 6.54
Company average	**$ 2.97**	$ 3.25	$ 1.50	**$ 3.11**	$ 1.88
Company average ($/BOE) (1) (2)	**$ 33.94**	$ 35.98	$ 27.28	**$ 34.99**	$ 23.21

(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 increased 55% to $44.47 per bbl for the six months ended June 30, 2017 from $28.78 per bbl for the six months ended June 30, 2016. North America realized crude oil prices averaged $44.78 per bbl for the second quarter of 2017, an increase of 19% compared with $37.59 per bbl for the second quarter of 2016 and comparable with $44.17 per bbl for the first quarter of 2017. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2017 from the comparable periods were primarily due to WTI benchmark pricing and fluctuations in the heavy differential and the Canadian dollar. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2017, contributed approximately 202,600 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 76% to average $2.96 per Mcf for the six months ended June 30, 2017 from $1.68 per Mcf for the six months ended June 30, 2016. North America realized natural gas prices increased 118% to average $2.84 per Mcf for the second quarter of 2017 compared with $1.30 per Mcf for the second quarter of 2016, and decreased 8% compared with $3.08 per Mcf for the first quarter of 2017. The increase in natural gas prices per Mcf for the three and six months ended June 30, 2017 from the comparable periods in 2016 reflected the rebalancing of natural gas storage inventory to historically normal levels, primarily due to reduced drilling activity in 2016, resulting in lower US natural gas production. Additionally, pricing reflected colder weather in the 2016/2017 winter season as compared with the previous year.

The decrease in realized natural gas prices for the second quarter of 2017 compared with the first quarter of 2017 reflected seasonal demand factors.

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

(Quarterly Average)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 46.44**	$ 47.10	$ 39.56
Pelican Lake heavy crude oil ($/bbl)	**$ 47.64**	$ 45.82	$ 40.60
Primary heavy crude oil ($/bbl)	**$ 45.92**	$ 45.22	$ 38.84
Bitumen (thermal oil) ($/bbl)	**$ 41.15**	$ 40.69	$ 32.91
Natural gas ($/Mcf)	**$ 2.84**	$ 3.08	$ 1.30

(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 increased 38% to average $67.49 per bbl for the six months ended June 30, 2017 from $48.90 per bbl for the six months ended June 30, 2016. North Sea realized crude oil prices increased 18% to average $64.37 per bbl for the second quarter of 2017 from $54.60 per bbl for the second quarter of 2016 and decreased 8% from $70.03 per bbl for the first quarter of 2017. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 29% to average $65.25 per bbl for the six months ended June 30, 2017 from $50.61 per bbl for the six months ended June 30, 2016. Offshore Africa realized crude oil prices increased 28% to average $69.93 per bbl for the second quarter of 2017 from $54.62 per bbl for the second quarter of 2016 and increased 13% from $61.95 per bbl for the first quarter of 2017. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 2017 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 5.19**	$ 5.45	$ 3.93	**$ 5.32**	$ 2.93
North Sea	**$ 0.14**	$ 0.13	$ 0.18	**$ 0.13**	$ 0.13
Offshore Africa	**$ 4.26**	$ 2.50	$ 2.12	**$ 3.23**	$ 2.05
Company average	**$ 4.83**	$ 4.89	$ 3.59	**$ 4.86**	$ 2.72
Natural gas ($/Mcf) (1)					
North America	**$ 0.12**	$ 0.18	$ 0.01	**$ 0.15**	$ 0.04
Offshore Africa	**$ 0.51**	$ 0.63	$ 0.27	**$ 0.58**	$ 0.29
Company average	**$ 0.12**	$ 0.19	$ 0.02	**$ 0.15**	$ 0.05
Company average ($/BOE) (1)	**$ 3.09**	$ 3.38	$ 2.13	**$ 3.24**	$ 1.70

(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 six months ended June 30, 2017 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential.

Crude oil and NGLs royalties averaged approximately 13% of product sales for the six months ended June 30, 2017 compared with 11% of product sales for the six months ended June 30, 2016. Crude oil and NGLs royalties averaged approximately 13% of product sales for the second quarter of 2017 compared with 11% for the second quarter of 2016 and 13% for the first quarter of 2017. The increase in royalties for the three and six months ended June 30, 2017 from the comparable periods in 2016 was primarily due to higher realized crude oil prices. North America crude oil and NGLs royalties per bbl are now anticipated to average 12% to 13% of product sales for 2017.

Natural gas royalties averaged approximately 6% of product sales for the six months ended June 30, 2017 compared with 3% of product sales for the six months ended June 30, 2016. Natural gas royalties averaged approximately 5% of product sales for the second quarter of 2017 compared with 1% for the second quarter of 2016 and 7% for the first quarter of 2017. The increase in natural gas royalties for the three and six months ended June 30, 2017 from the comparable periods in 2016 reflected higher realized natural gas prices in the current period. The decrease in natural gas royalties in the second quarter of 2017 from the first quarter of 2017 primarily reflected lower realized natural gas prices in the second quarter of 2017. North America natural gas royalties are now anticipated to average 5% to 7% of product sales for 2017.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 5% for the six months ended June 30, 2017, compared with 4% of product sales for the six months ended June 30, 2016. Royalty rates as a percentage of product sales averaged approximately 6% for the second quarter of 2017, compared with 4% of product sales for the second quarter of 2016 and 5% for the first quarter of 2017. Royalties as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields. Offshore Africa royalty rates are anticipated to average 7% to 9% of product sales for 2017.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2017	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 13.74**	$ 12.22	$ 12.30	**$ 12.96**	$ 11.86
North Sea	**$ 28.86**	$ 36.86	$ 40.74	**$ 33.28**	$ 44.89
Offshore Africa	**$ 32.39**	$ 18.54	$ 20.13	**$ 24.27**	$ 19.08
Company average	**$ 15.51**	$ 14.37	$ 14.31	**$ 14.92**	$ 14.12
Natural gas ($/Mcf) [1]					
North America	**$ 1.17**	$ 1.20	$ 1.17	**$ 1.19**	$ 1.18
North Sea	**$ 3.40**	$ 3.07	$ 3.33	**$ 3.23**	$ 3.69
Offshore Africa	**$ 3.88**	$ 3.50	$ 1.76	**$ 3.66**	$ 1.55
Company average	**$ 1.25**	$ 1.28	$ 1.22	**$ 1.26**	$ 1.23
Company average ($/BOE) [1]	**$ 12.11**	$ 11.67	$ 11.38	**$ 11.89**	$ 11.28

(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 six months ended June 30, 2017 increased 9% to $12.96 per bbl from $11.86 per bbl for the six months ended June 30, 2016. North America crude oil and NGLs production expense for the second quarter of 2017 of $13.74 per bbl increased 12% from $12.30 per bbl in the second quarter of 2016 and increased 12% from $12.22 per bbl for the first quarter of 2017.The Company continues to focus on cost control and achieving efficiencies across the asset base. Production expense per barrel during the second quarter of 2017 reflected the impact of lower volumes on a fixed cost basis, service cost pressures and seasonality in heavy oil. North America crude oil and NGLs production expense is anticipated to average $11.50 to $13.50 per bbl for 2017.

North America natural gas production expense for the six months ended June 30, 2017 averaged $1.19 per Mcf, comparable with $1.18 per Mcf for the six months ended June 30, 2016. North America natural gas production expense for the second quarter of 2017 of $1.17 per Mcf, was comparable with $1.17 per Mcf for the second quarter of 2016 and decreased 3% from $1.20 per Mcf for the first quarter of 2017. The Company continues to focus on cost control and achieving efficiencies across the asset base. North America natural gas production expense guidance is anticipated to average $1.00 to $1.20 per Mcf for 2017.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2017 decreased 26% to $33.28 per bbl from $44.89 per bbl for the six months ended June 30, 2016. North Sea crude oil production expense for the second quarter of 2017 decreased 29% to $28.86 per bbl from $40.74 per bbl for the second quarter of 2016 and decreased 22% from $36.86 per bbl in the first quarter of 2017. The Company continues to manage its production costs and achieve efficiencies through focused cost and production optimization. Production expense for the three and six months ended June 30, 2017 also reflected fluctuations in the Canadian dollar and the UK pound sterling and the impact of higher volumes on a fixed cost basis. North Sea crude oil production expense guidance is anticipated to average $33.00 to $36.00 per bbl for 2017.

Offshore Africa

Offshore Africa crude oil production expense of $24.27 per bbl for the six months ended June 30, 2017 included production expense of $12.48 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Production expense of $32.39 per bbl for the second quarter of 2017 included production expense of $17.27 per bbl relating to the Baobab and Espoir fields in Côte d'Ivoire. Fluctuations in production expense for the three and six months ended June 30, 2017 from the comparable periods primarily reflected the timing of liftings from various fields, including the Olowi field, which have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned turnarounds at Espoir in the second quarter of 2017 and fluctuations in the Canadian dollar. Offshore Africa production expense guidance is anticipated to average $10.50 to $12.50 per bbl for 2017.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Expense	**$ 971**	$ 1,102	$ 1,036	**$ 2,073**	$ 2,105
$/BOE (1)	**$ 16.38**	$ 17.68	$ 17.03	**$ 17.05**	$ 16.81

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

The decrease in depletion, depreciation and amortization expense for the three and six months ended June 30, 2017 from the comparable periods in 2016 was primarily due to lower sales volumes and depletion rates in North America, partially offset by additional depletion, depreciation and amortization in the North Sea related to the abandonment of the Ninian North platform.

Depletion, depreciation and amortization on a per barrel basis for the six months ended June 30, 2017 averaged $17.05 per BOE, comparable with $16.81 per BOE for the six months ended June 30, 2016. Depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2017 decreased 4% to $16.38 per BOE from $17.03 per BOE for the second quarter of 2016 and decreased 7% from $17.68 per BOE for the first quarter of 2017. Depletion, depreciation and amortization expense on a per barrel basis for the six months ended June 30, 2017 reflected depletion of $225 million in the North Sea related to the abandonment of the Ninian North platform, partially offset by a lower depletable base in North America. The decrease in depletion, depreciation and amortization expense per BOE for the second quarter of 2017 from the second quarter of 2016 reflected lower sales volumes and depletion rates in North America. The decrease from the first quarter of 2017 reflected depletion of $151 million in the North Sea during the first quarter of 2017 related to the abandonment of the Ninian North platform compared with $74 million in the second quarter of 2017.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Expense	**$ 29**	$ 28	$ 28	**$ 57**	$ 57
$/BOE (1)	**$ 0.48**	$ 0.45	$ 0.46	**$ 0.47**	$ 0.45

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

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

Asset retirement obligation accretion expense for the six months ended June 30, 2017 increased 4% to $0.47 per BOE from $0.45 per BOE for the six months ended June 30, 2016. Asset retirement obligation accretion expense for the second quarter of 2017 increased 4% to $0.48 per BOE from $0.46 per BOE for the second quarter of 2016, and increased 7% from $0.45 per BOE for the first quarter of 2017.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

On May 31, 2017 the Company completed the acquisition of a direct and indirect 70% interest in AOSP including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta and 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project. The acquisition strengthens the Company's portfolio of long life, low decline synthetic crude oil assets. Effective May 31, the Oil Sands Mining and Upgrading segment of this MD&A reflects the mining, extraction and upgrading operations at both Horizon and AOSP.

The Company continues to focus on reliable and efficient operations. The Oil Sands Mining and Upgrading segment achieved record production during the second quarter of 2017 averaging 257,541 bbl/d following the addition of production volumes from the acquisition of and successful integration of the Company's interest in AOSP.

Horizon Operations Update

The Company continues to focus on reliable and efficient operations. Horizon achieved SCO production averaging 190,837 bbl/d during the second quarter of 2017. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability, together with additional capacity from Phase 2B and utilization of available Phase 3 infrastructure, cash production costs averaging $22.09 per bbl were achieved during the quarter.

The Horizon Phase 3 expansion, which is anticipated to add 80,000 bbl/d of SCO production, is on schedule and within targeted cost, with commissioning and startup targeted in the fourth quarter of 2017 bringing total plant capacity to 250,000 bbl/d.

AOSP Operations Update

For the second quarter of 2017, AOSP SCO production volumes averaged 66,704 bbl/d, representing an average of 202,300 bbl/d for the month of June, reflecting high reliability of operations. Cash production costs of $27.50 per bbl were achieved during the quarter.

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

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Sales Price (2) (3)	**$ 63.39**	$ 67.85	$ 61.78	**$ 65.25**	$ 54.11
Bitumen value for royalty purposes(4)	**$ 39.99**	$ 36.07	$ 30.93	**$ 38.37**	$ 20.84
Bitumen Royalties(5)	**$ 1.38**	$ 1.14	$ 0.39	**$ 1.28**	$ 0.26
Transportation	**$ 1.32**	$ 1.17	$ 1.34	**$ 1.26**	$ 1.71

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

(2) The realized sales price for the three months ended June 30, 2017 reflects the weighted average price of Horizon SCO and AOSP SCO. The realized sales price for the comparable periods reflects the Horizon SCO price only.

(3) Net of blending and feedstock costs.

(4) Calculated as the quarterly average of the bitumen valuation methodology price.

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $65.25 per bbl for the six months ended June 30, 2017, an increase of 21% compared with $54.11 per bbl for the six months ended June 30, 2016. The realized sales price averaged $63.39 per bbl for the second quarter of 2017, an increase of 3% compared with $61.78 per bbl for the second quarter of 2016 and a 7% decrease from $67.85 per bbl for the first quarter of 2017. The realized sales price for the three months ended June 30, 2017 reflects the weighted average price of Horizon SCO and AOSP SCO. The realized sales price for the comparable periods reflects the Horizon SCO price only.

The realized SCO sales price for Horizon averaged $67.43 per bbl for the six months ended June 30, 2017, an increase of 25% from $54.11 per bbl for the six months ended June 30, 2016. For the second quarter of 2017, the realized sales price increased 9% to $67.04 per bbl from $61.78 per bbl for the second quarter of 2016 and was comparable with $67.85 per bbl for the first quarter of 2017. Realized sales prices for the three and six months ended June 30, 2017 reflected fluctuations in WTI benchmark pricing and the impact of unplanned third party oil sands production outages during the second quarter of 2017.

The realized sales price for AOSP SCO averaged $52.35 per bbl for the month of June, partially reflecting prevailing WTI pricing for the month of June of US$45.20 per bbl.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Cash production costs, excluding natural gas costs	**$ 515**	$ 339	$ 278	**$ 854**	$ 560
Natural gas costs	**38**	33	15	**71**	30
Cash production costs	**$ 553**	$ 372	$ 293	**$ 925**	$ 590

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Cash production costs, excluding natural gas costs	**$ 21.85**	$ 20.11	$ 25.44	**$ 21.12**	$ 25.30
Natural gas costs	**1.59**	1.97	1.38	**1.75**	1.38
Cash production costs	**$ 23.44**	$ 22.08	$ 26.82	**$ 22.87**	$ 26.68
Sales (bbl/d)	**259,033**	187,276	119,988	**223,353**	121,517

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

Cash production costs for the six months ended June 30, 2017 decreased 14% to $22.87 per bbl from $26.68 per bbl for the six months ended June 30, 2016. Cash production costs for the second quarter of 2017 averaged $23.44 per bbl, a decrease of 13% from $26.82 per bbl for the second quarter of 2016 and a 6% increase from $22.08 per bbl for the first quarter of 2017. The decrease in cash production costs on a per barrel basis for the three and six months ended June 30, 2017 from the comparable periods in 2016 primarily reflected the Company's continuous focus on cost control and efficiencies and high utilization rates and reliability, together with additional capacity from Phase 2B and Phase 3 infrastructure during the second quarter of 2017, partially offset by the impact of the acquisition of AOSP. The increase in cash production costs in the second quarter of 2017 compared with the first quarter of 2017 reflected the acquisition of AOSP.

Horizon cash production costs for the six months ended June 30, 2017 decreased 17% to $22.09 per bbl from $26.68 per bbl for the six months ended June 30, 2016. Cash production costs for the second quarter of 2017 averaged $22.09 per bbl, a decrease of 18% from $26.82 per bbl for the second quarter of 2016 and comparable with $22.08 per bbl for the first quarter of 2017. For 2017, Horizon cash production costs are anticipated to average $24.00 to $27.00 per bbl, including turnaround costs.

AOSP cash production costs for the month of June were $27.50 per bbl. For 2017, AOSP cash production costs are anticipated to average $27.00 to $31.00 per bbl.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Expense	**$ 237**	$ 195	$ 135	**$ 432**	$ 282
$/bbl (1)	**$ 10.05**	$ 11.58	$ 12.32	**$ 10.69**	$ 12.72

(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 Oil Sands Mining and Upgrading segment for the six months ended June 30, 2017 decreased 16% to $10.69 per bbl from $12.72 per bbl for the six months ended June 30, 2016. Depletion, depreciation and amortization expense on a per barrel basis for the second quarter of 2017 decreased 18% to $10.05 per bbl from $12.32 per bbl for the second quarter of 2016 and decreased 13% from $11.58 per bbl for the first quarter of 2017.

Depletion, depreciation and amortization expense per barrel for the three and six months ended June 30, 2017 decreased from the comparable periods primarily due to the impact of increased production volumes on assets depreciated on a straight line basis at Horizon and reflected additional AOSP depletion, depreciation and amortization, which has a lower depletion, depreciation and amortization rate.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Expense	**$ 10**	$ 8	$ 7	**$ 18**	$ 14
$/bbl (1)	**$ 0.42**	$ 0.46	$ 0.67	**$ 0.44**	$ 0.66

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

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

Asset retirement obligation accretion expense for the six months ended June 30, 2017 decreased 33% to $0.44 per bbl from $0.66 per bbl for the six months ended June 30, 2016. Asset retirement obligation accretion expense of $0.42 per bbl for the second quarter of 2017 decreased 37% from $0.67 per bbl for the second quarter of 2016 and decreased 9% from $0.46 per bbl for the first quarter of 2017, primarily due to higher sales volumes.

MIDSTREAM

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Revenue	**$ 23**	$ 25	$ 31	**$ 48**	$ 57
Production expense	**4**	4	7	**8**	13
Midstream cash flow	**19**	21	24	**40**	44
Depreciation	**2**	2	3	**4**	6
Equity (gain) loss on investments	**(10)**	(2)	3	**(12)**	(23)
Segment earnings before taxes	**$ 27**	$ 21	$ 18	**$ 48**	$ 61

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

During 2013, the Company along with APMC, initially committed each to provide funding up to $350 million by each party by January 2016 in the form of subordinated debt bearing interest at prime plus 6%, based on a facility capital cost ("FCC") budget at $8,500 million, which has subsequently been increased by approximately 11% to the current estimate of approximately $9,400 million. A higher than expected USD/CAD exchange rate, scope changes, and productivity challenges during construction have resulted in upward budgetary pressures. Partially offsetting these FCC increases are lower than budgeted interest rates which the Partnership has been able to lock in to date.

The Company and APMC have agreed, each with a 50% interest, to provide additional subordinated debt as required for Project costs in excess of the FCC of $8,500 million to reflect an agreed debt to equity ratio of 80/20 and, subject to the Company being able to meet certain funding conditions, to fund any shortfall in available third party commercial lending required to attain Project completion which is currently targeted for mid-2018. The Company's share of any additional subordinated debt financing resulting from the increase in the FCC in excess of $8,500 million is not expected to be significant. For the six months ended June 30, 2017, the Company and APMC each contributed an additional $23 million. To June 30, 2017, each party has provided $347 million of subordinated debt, together with accrued interest thereon of $78 million, for a Company total of $425 million.

During the second quarter of 2017, Redwater Partnership issued $750 million of 2.80% series J senior secured bonds due June 2027 and $750 million of 3.65% series K senior secured bonds due June 2035.

As at June 30, 2017, Redwater Partnership had additional borrowings of $931 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

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Expense	**$ 75**	$ 87	$ 91	**$ 162**	$ 177
$/BOE (1)	**$ 0.90**	$ 1.10	$ 1.27	**$ 1.00**	$ 1.20

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

Administration expense on a per BOE basis for the six months ended June 30, 2017 decreased 17% to $1.00 per BOE from $1.20 per BOE for the six months ended June 30, 2016. Administration expense for the second quarter of 2017 of $0.90 per BOE decreased 29% from $1.27 per BOE for the second quarter of 2016 and decreased 18% from $1.10 per BOE for the first quarter of 2017. Administration expense per BOE decreased for the six months ended June 30, 2017 from comparable periods primarily due to higher overhead recoveries and higher sales volumes.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
(Recovery) expense	**$ (104)**	$ 27	$ 122	**$ (77)**	$ 239

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 $77 million share-based compensation recovery for the six months ended June 30, 2017, 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 six months ended June 30, 2017, the Company recovered $18 million of share-based compensation costs from property, plant and equipment in the Oil Sands Mining and Upgrading segment (June 30, 2016 – $48 million costs capitalized).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended						Six Months Ended			
($ millions, except per BOE amounts and interest rates)		**Jun 30 2017**		Mar 31 2017		Jun 30 2016		**Jun 30 2017**		Jun 30 2016
Expense, gross	**$**	**166**	$	156	$	153	**$**	**322**	$	306
Less: capitalized interest		**21**		22		67		**43**		128
Expense, net	**$**	**145**	$	134	$	86	**$**	**279**	$	178
$/BOE (1)	**$**	**1.74**	$	1.70	$	1.19	**$**	**1.72**	$	1.21
Average effective interest rate		**3.9%**		3.9%		3.9%		**3.9%**		3.9%

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

Gross interest and other financing expense for the three and six months ended June 30, 2017 increased from the comparable periods primarily due to the impact of higher average debt levels as a result of financing pertaining to the acquisition of AOSP and other assets. Capitalized interest of $43 million for the six months ended June 30, 2017 was primarily related to the Horizon Phase 3 expansion.

Net interest and other financing expense on a per BOE basis for the six months ended June 30, 2017 increased 42% to $1.72 per BOE from $1.21 per BOE for the six months ended June 30, 2016. Net interest and other financing expense on a per BOE basis for the second quarter of 2017 increased 46% to $1.74 per BOE from $1.19 per BOE for the second quarter of 2016 and was comparable with the first quarter of 2017. The increase for the three and six months ended June 30, 2017 from the comparable periods in 2016 was primarily due to higher average debt levels as a result of financing pertaining to the acquisition of AOSP and other assets, and lower capitalized interest related to the completion of Horizon Phase 2B.

The Company’s average effective interest rate for the three and six months ended June 30, 2017 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.

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Crude oil and NGLs financial instruments	**$ (17)**	$ (1)	$ —	**$ (18)**	$ —
Natural gas financial instruments	**(1)**	—	—	**(1)**	—
Foreign currency contracts	**5**	(11)	49	**(6)**	45
Realized (gain) loss	**(13)**	(12)	49	**(25)**	45
Crude oil and NGLs financial instruments	**(30)**	(43)	—	**(73)**	—
Natural gas financial instruments	**(1)**	(8)	—	**(9)**	—
Foreign currency contracts	**25**	11	(52)	**36**	22
Unrealized (gain) loss	**(6)**	(40)	(52)	**(46)**	22
Net (gain) loss	**$ (19)**	$ (52)	$ (3)	**$ (71)**	$ 67

During the six months ended June 30, 2017, net realized risk management gains were primarily related to the settlement of crude oil and foreign currency contracts. The Company recorded a net unrealized gain of $46 million ($29 million after-tax) on its risk management activities for the six months ended June 30, 2017, including an unrealized gain of $6 million ($2 million loss after-tax) for the second quarter of 2017 (March 31, 2017 – unrealized gain of $40 million; $31 million after-tax; June 30, 2016 – unrealized gain of $52 million; $46 million after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2017 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Net realized loss	**$ 8**	$ 4	$ 9	**$ 12**	$ 28
Net unrealized (gain) loss	**(355)**	(60)	40	**(415)**	(294)
Net (gain) loss (1)	**$ (347)**	$ (56)	$ 49	**$ (403)**	$ (266)

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

The net realized foreign exchange loss for the six months ended June 30, 2017 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the six months ended June 30, 2017 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized gain for each of the periods presented included the impact of cross currency swaps (three months ended June 30, 2017 – unrealized loss of $208 million, March 31, 2017 – unrealized loss of $23 million, June 30, 2016 – unrealized gain of $9 million; six months ended June 30, 2017 - unrealized loss of $231 million, June 30, 2016 - unrealized loss of $339 million). The US/Canadian dollar exchange rate at June 30, 2017 was US$0.7703 (March 31, 2017 – US$0.7506, June 30, 2016 – US$0.7687).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2017	Mar 31 2017	Jun 30 2016	Six Months Ended Jun 30 2017	Jun 30 2016
North America [1]	**$ (47)**	$ 38	$ (68)	**$ (9)**	$ (187)
North Sea	**30**	6	(8)	**36**	(31)
Offshore Africa	**7**	7	8	**14**	12
PRT recovery – North Sea	**(72)**	(1)	(31)	**(73)**	(86)
Other taxes	**3**	3	3	**6**	4
Current income tax (recovery) expense	**(79)**	53	(96)	**(26)**	(288)
Deferred corporate income tax expense (recovery)	**110**	28	(52)	**138**	(19)
Deferred PRT expense (recovery) – North Sea	**52**	8	10	**60**	(194)
Deferred income tax expense (recovery)	**162**	36	(42)	**198**	(213)
	83	89	(138)	**172**	(501)
Income tax rate and other legislative changes[2]	**—**	—	—	**—**	114
	$ 83	$ 89	$ (138)	**$ 172**	$ (387)
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**20%**	20%	37%	**20%**	31%

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

(2) During the first quarter of 2016 the UK government enacted tax rate reductions relating to PRT, resulting in a decrease in the Company's net deferred income tax liability of $114 million.

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

The effective income tax rate for the three and six months ended June 30, 2017 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income (loss) and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current PRT recovery in the North Sea in the three and six months ended June 30, 2017 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison platform.

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

For 2017, the Company expects to recognize current income tax recoveries ranging from $nil to $100 million in Canada and $20 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Jun 30 2017	Three Months Ended Mar 31 2017	Three Months Ended Jun 30 2016	Six Months Ended Jun 30 2017	Six Months Ended Jun 30 2016
Exploration and Evaluation					
Net expenditures (proceeds) [(2) (3) (4)]	**$ 30**	$ 37	$ 20	**$ 67**	$ (10)
Property, Plant and Equipment					
Net property acquisitions [(2) (3) (4)]	**371**	9	110	**380**	141
Well drilling, completion and equipping	**208**	340	98	**548**	326
Production and related facilities	**194**	167	94	**361**	215
Capitalized interest and other [(5)]	**21**	21	21	**42**	45
Net expenditures	**794**	537	323	**1,331**	727
Total Exploration and Production	**824**	574	343	**1,398**	717
Horizon Oil Sands Mining and Upgrading					
Horizon Phases 2/3 construction costs	**182**	139	583	**321**	1,005
Sustaining capital	**77**	67	76	**144**	152
Turnaround costs	**10**	1	29	**11**	35
Capitalized interest and other [(5)]	**(3)**	20	86	**17**	167
Total Horizon Oil Sands Mining and Upgrading	**266**	227	774	**493**	1,359
Athabasca Oil Sands Project					
Acquisitions of Exploration and Evaluation assets[(2)(4)]	**219**	—	—	**219**	—
Net property acquisitions [(2)(4)]	**11,604**	—	—	**11,604**	—
Sustaining capital	**8**	—	—	**8**	—
Total Athabasca Oil Sands Project	**11,831**	—	—	**11,831**	—
Total Oil Sands Mining and Upgrading	**$ 12,097**	$ 227	$ 774	**$ 12,324**	$ 1,359
Midstream	**1**	1	1	**2**	2
Abandonments [(6)]	**105**	41	36	**146**	110
Head office	**19**	3	4	**22**	10
Total net capital expenditures	**$ 13,046**	$ 846	$ 1,158	**$ 13,892**	$ 2,198
By segment					
North America [(2) (3) (4)]	**$ 765**	$ 520	$ 319	**$ 1,285**	$ 568
North Sea	**41**	35	10	**76**	26
Offshore Africa	**18**	19	14	**37**	123
Oil Sands Mining and Upgrading[(4)]	**12,097**	227	774	**12,324**	1,359
Midstream	**1**	1	1	**2**	2
Abandonments [(6)]	**105**	41	36	**146**	110
Head office	**19**	3	4	**22**	10
Total	**$ 13,046**	$ 846	$ 1,158	**$ 13,892**	$ 2,198

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

(2) Includes Business Combinations.

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

(4) Total purchase consideration for the acquisition of interests in AOSP of $12,157 million includes $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.

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

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

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

Net capital expenditures for the six months ended June 30, 2017 were $13,892 million compared with $2,198 million for the six months ended June 30, 2016. Net capital expenditures for the second quarter of 2017 were $13,046 million, compared with $1,158 million for the second quarter of 2016 and $846 million for the first quarter of 2017.

Included in net capital expenditures for the three and six months ended June 30, 2017 was $12,157 million related to the acquisition of AOSP and other assets.

Drilling Activity

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2017**	Mar 31 2017	Jun 30 2016	**Jun 30 2017**	Jun 30 2016
Net successful natural gas wells	**5**	11	1	**16**	5
Net successful crude oil wells (1)	**61**	155	—	**216**	8
Dry wells	**2**	1	—	**3**	—
Stratigraphic test / service wells	**6**	226	1	**232**	200
Total	**74**	393	2	**467**	213
Success rate (excluding stratigraphic test / service wells)	**97%**	99%	100%	**99%**	100%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 9% of the total net capital expenditures for the six months ended June 30, 2017 compared with approximately 28% for the six months ended June 30, 2016.

During the second quarter of 2017, the Company targeted 5 net natural gas wells, including 3 wells in Northeast British Columbia and 2 wells in Northwest Alberta. The Company also targeted 61 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 39 primary heavy crude oil wells, 9 Pelican Lake heavy crude oil wells and 4 bitumen (thermal oil) wells and 1 light crude oil well were drilled. Another 8 wells targeting light crude oil were drilled outside the Northern Plains region.

Overall thermal oil production for the second quarter of 2017 averaged approximately 105,700 bbl/d compared with approximately 93,200 bbl/d for the second quarter of 2016 and approximately 128,400 bbl/d for the first quarter of 2017. Production volumes in the second quarter of 2017 primarily reflected the successful completion of planned turnarounds at the Primrose and Kirby South plants during the second quarter of 2017, and were within guidance.

Pelican Lake production for the second quarter of 2017 averaged approximately 46,900 bbl/d, comparable with 47,800 bbl/d in the second quarter of 2016 and 46,600 bbl/d in the first quarter of 2017.

Horizon Oil Sands Mining and Upgrading

All Horizon Phase 2 Plants are now commissioned and activity during the second quarter focused on optimization of plant production. Phase 3 expansion work also continued with field construction of the combined hydrotreater and sulphur recovery units.

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

North Sea

During the first quarter of 2017, the Company completed one injection well (0.9 on a net basis) at Ninian. During the second quarter of 2017, the Company completed two production wells (1.8 on a net basis) and one injection well (0.9 on a net basis) at Ninian.

During the second quarter of 2017, the Company ceased production at the Ninian North field, and commenced well plugging and abandonment. The Company also completed all the heavy lifts at the Murchison platform during the second quarter of 2017, on time and within budget.

LIQUIDITY AND CAPITAL RESOURCES

	Three Months Ended			
($ millions, except ratios)	**Jun 30 2017**	Mar 31 2017	Dec 31 2016	Jun 30 2016
Working capital (1)	**$ 876**	$ 1,222	$ 1,056	$ 686
Long-term debt (2) (3)	**$ 23,276**	$ 16,304	$ 16,805	$ 17,236
Share capital	**$ 8,771**	$ 4,869	$ 4,671	$ 4,167
Retained earnings	**22,203**	21,465	21,526	21,816
Accumulated other comprehensive income	**12**	43	70	36
Shareholders' equity	**$ 30,986**	$ 26,377	$ 26,267	$ 26,019
Debt to book capitalization (3) (4)	**43%**	38%	39%	40%
Debt to market capitalization (3) (5)	**34%**	25%	26%	28%
After-tax return on average common shareholders' equity (6)	**6%**	1%	(1)%	(2)%
After-tax return on average capital employed (3) (7)	**4%**	1%	0%	0%

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

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

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

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

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

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

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

At June 30, 2017, the Company's capital resources consisted primarily of funds flow from operations, available bank credit facilities and access to debt capital markets. Funds flow from operations and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2016. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated funds flow from operations supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long term and support its growth strategy.

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

- Monitoring funds flow from operations, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. In response to the current commodity price environment, the Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2017, the Company extended $2,095 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $330 million outstanding under this facility will continue under the previous terms and mature in June 2019. The other $2,425 million revolving credit facility matures in June 2020. Each of the revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans.
  - During the second quarter of 2017, the $1,500 million non-revolving term credit facility was increased to $2,200 million and the maturity date was extended to October 2019 from April 2018. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. As at June 30, 2017, the $2,200 million facility was fully drawn.
  - As at June 30, 2017, the $750 million and $125 million facilities were each fully drawn. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances or Canadian prime loans.
  - In addition, to the credit facilities described above, during the second quarter of 2017, the Company entered into a $3,000 million non-revolving term loan facility to finance the acquisition of AOSP and other assets. This facility matures in May 2020 and is subject to an annual amortization of 5% of the original balance. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar or US dollar bankers' acceptances, or LIBOR, US base rate or Canadian prime loans. This facility supports a US$375 million letter of credit regarding the deferred purchase consideration payable to Marathon in March 2018. As at June 30, 2017, the $3,000 million facility was fully drawn.
  - During the second quarter of 2017, the Company issued $900 million of 2.05% medium-term notes due June 2020, $600 million of 3.42% medium-term notes due December 2026 and $300 million of 4.85% medium-term notes due May 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. Subsequent to June 30, 2017, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019, replacing the Company's previous base shelf prospectus, which would have expired in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market condition at the time of issuance.
  - During the second quarter of 2017, the Company repaid US$1,100 million of 5.70% notes. In addition, the Company issued US$1,000 million of 2.95% notes due January 2023, US$1,250 million of 3.85% notes due June 2027 and US$750 million of 4.95% notes due June 2047. Proceeds from the securities were used to finance the acquisition of AOSP and other assets. Subsequent to June 30, 2017 the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2019, replacing the Company's previous base shelf prospectus which would have expired in November 2017. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market condition at the time of issuance.

- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under the US commercial paper program.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place to minimize the impact in the event of a default.

As at June 30, 2017, the Company had in place bank credit facilities of $11,050 million, of which $3,671 million was available. This excludes certain dedicated credit facilities supporting letters of credit.

At June 30, 2017, the Company had total US dollar denominated debt with a carrying amount of $13,463 million (US $10,370 million), excluding transaction costs. This included $3,599 million (US$2,770 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$1,720 million). The fixed repayment amount of these hedging instruments is $3,455 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $144 million to $13,319 million as at June 30, 2017.

Long-term debt was $23,276 million at June 30, 2017, resulting in a debt to book capitalization ratio of 43% (December 31, 2016 – 39%, June 30, 2016 – 40%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when funds flow from operations is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. In connection with the acquisition of AOSP and other assets, the Company arranged acquisition financing of $1.8 billion of medium-term notes in Canada, US$3 billion of long-term notes in the United States and a $3 billion term loan facility. See Note 8 in the unaudited interim consolidated financial statements.

Further details related to the Company's long-term debt at June 30, 2017 are discussed in note 8 to the Company's unaudited interim consolidated financial statements.

The Company's commodity hedge policy reduces the risk of volatility in commodity prices and supports the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. At June 30, 2017, 50,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for July 2017 to October 2017. At June 30, 2017, 67,500 bbl/d of currently forecasted crude oil volumes were hedged using WTI collars for July 2017 to December 2017. Further details related to the Company's commodity derivative financial instruments at June 30, 2017 are discussed in note 15 to the Company's unaudited interim consolidated financial statements.

Share Capital

As at June 30, 2017, there were 1,215,058,000 common shares outstanding (December 31, 2016 – 1,110,952,000 common shares) and 57,862,000 stock options outstanding. As at August 1, 2017, the Company had 1,215,215,000 common shares outstanding and 57,433,000 stock options outstanding.

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

On May 16, 2017, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 27,931,135 common shares, over a 12 month period commencing May 23, 2017 and ending May 22, 2018. For the six months ended June 30, 2017, 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. In connection with the acquisition of AOSP and other assets, the Company also assumed certain pipeline and other commitments. The following table summarizes the Company's commitments as at June 30, 2017:

($ millions)	Remaining 2017	2018	2019	2020	2021	Thereafter
Product transportation and pipeline	$ 291	$ 569	$ 422	$ 401	$ 345	$ 3,710
Offshore equipment operating leases and offshore drilling	$ 112	$ 187	$ 96	$ 72	$ 71	$ 8
Long-term debt (1)	$ 649	$ 1,448	$ 4,205	$ 4,789	$ 649	$ 11,683
Interest and other financing expense (2)	$ 399	$ 817	$ 756	$ 646	$ 573	$ 6,095
Office leases	$ 24	$ 46	$ 44	$ 43	$ 40	$ 152
Other	$ 56	$ 46	$ 42	$ 41	$ 40	$ 384

(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 June 30, 2017.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction 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, 2016 and the unaudited interim consolidated financial statements for the three and six months ended June 30, 2017.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the annual MD&A and the audited consolidated financial statements for the year ended December 31, 2016.