Canadian Natural

Canadian Natural Resources Limited

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2019

MANAGEMENT'S DISCUSSION AND ANALYSIS

ADVISORY

Special Note Regarding 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, production expenses, capital expenditures, income tax expenses and other guidance provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, 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 ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the timing and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the development and deployment of technology and technological innovations also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are 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 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 reserves 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; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); 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 expenditures and production expenses); 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 national, 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 MD&A could also have 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 applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("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, cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings from operations is reconciled to net earnings, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" 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.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2019 and the MD&A and the audited consolidated financial statements of the Company for the year ended December 31, 2018. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three and nine months ended September 30, 2019 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new "Leases" standard, comparative period balances in 2018 reported in this MD&A have not been restated.

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalties" or "company gross" basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A 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 on an "after royalties" or "company net" basis is also presented in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2019 in relation to the comparable periods in 2018 and the second quarter of 2019. 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, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com, provided that such guidance does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated November 6, 2019.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Sep 30 2019**	 Jun 30 2019	 Sep 30 2018	Nine Months Ended **Sep 30 2019**	 Sep 30 2018
Product sales [1]	**$ 6,587**	$ 5,931	$ 6,327	**$ 18,059**	$ 18,451
Crude oil and NGLs	**$ 6,324**	$ 5,597	$ 5,967	**$ 17,003**	$ 17,341
Natural gas	**$ 257**	$ 324	$ 360	**$ 1,037**	$ 1,110
Net earnings	**$ 1,027**	$ 2,831	$ 1,802	**$ 4,819**	$ 3,367
Per common share – basic	**$ 0.87**	$ 2.37	$ 1.48	**$ 4.04**	$ 2.75
– diluted	**$ 0.87**	$ 2.36	$ 1.47	**$ 4.03**	$ 2.74
Adjusted net earnings from operations [2]	**$ 1,229**	$ 1,042	$ 1,354	**$ 3,109**	$ 3,518
Per common share – basic	**$ 1.04**	$ 0.87	$ 1.11	**$ 2.61**	$ 2.88
– diluted	**$ 1.04**	$ 0.87	$ 1.11	**$ 2.60**	$ 2.86
Cash flows from operating activities	**$ 2,518**	$ 2,861	$ 3,642	**$ 6,375**	$ 8,724
Adjusted funds flow [3]	**$ 2,881**	$ 2,652	$ 2,830	**$ 7,773**	$ 7,859
Per common share – basic	**$ 2.43**	$ 2.22	$ 2.32	**$ 6.51**	$ 6.42
– diluted	**$ 2.43**	$ 2.22	$ 2.31	**$ 6.50**	$ 6.39
Cash flows used in investing activities	**$ 908**	$ 4,464	$ 1,265	**$ 6,401**	$ 3,772
Net capital expenditures [4]	**$ 963**	$ 4,125	$ 1,473	**$ 6,065**	$ 3,550

(1) Further details related to product sales, including 'Other' income, for the three and nine months ended September 30, 2019 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

(2) Adjusted net earnings from operations is a non-GAAP measure that represents net earnings as presented in the Company's consolidated Statements of Earnings, adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation "Adjusted Net Earnings from Operations, as Reconciled to Net Earnings" is presented in this MD&A. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(3) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance 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 "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(4) Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business combinations and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations, as Reconciled to Net Earnings

($ millions)	Three Months Ended Sep 30 2019	Three Months Ended Jun 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Net earnings	**$ 1,027**	$ 2,831	$ 1,802	**$ 4,819**	$ 3,367
Share-based compensation, net of tax (1)	**7**	(7)	(85)	**62**	2
Unrealized risk management gain, net of tax (2)	**(2)**	(13)	(11)	**(2)**	(53)
Unrealized foreign exchange loss (gain), net of tax (3)	**129**	(219)	(182)	**(323)**	158
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	—	—	**—**	146
Loss from investments, net of tax (5) (6)	**68**	68	89	**171**	240
Gain on acquisition and revaluation of properties, net of tax (7)	**—**	—	(259)	**—**	(342)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	(1,618)	—	**(1,618)**	—
Adjusted net earnings from operations	**$ 1,229**	$ 1,042	$ 1,354	**$ 3,109**	$ 3,518

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

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

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

(4) During the first quarter of 2018, the Company repaid US$600 million of 1.75% notes and US$400 million of 5.90% notes.

(5) 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 loss from investments is the Company's pro rata share of the Redwater Partnership's equity loss for the period.

(6) 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 measured each period with changes in fair value recognized in net earnings.

(7) During the third quarter of 2018, the Company recorded a pre-tax gain of $272 million ($259 million after-tax) related to acquisitions in the North America Exploration and Production segment. During the second quarter of 2018, the Company recorded a pre-tax gain of $120 million ($72 million after-tax) on the acquisition of the remaining interest at Ninian in the North Sea and a pre-tax gain of $19 million ($11 million after-tax) relating to the revaluation of the Company's previously held interest at Ninian.

(8) In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities (1)

($ millions)	Three Months Ended Sep 30 2019	Three Months Ended Jun 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Cash flows from operating activities	**$ 2,518**	$ 2,861	$ 3,642	**$ 6,375**	$ 8,724
Net change in non-cash working capital	**299**	(230)	(889)	**1,085**	(1,067)
Abandonment expenditures (2)	**63**	41	57	**212**	197
Other (3)	**1**	(20)	20	**101**	5
Adjusted funds flow	**$ 2,881**	$ 2,652	$ 2,830	**$ 7,773**	$ 7,859

(1) Adjusted funds flow was previously referred to as funds flow from operations.

(2) The Company includes abandonment expenditures in "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" in the "Net Capital Expenditures" section of this MD&A.

(3) Movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the nine months ended September 30, 2019 were $4,819 million compared with $3,367 million for the nine months ended September 30, 2018. Net earnings for the nine months ended September 30, 2019 included net after-tax income of $1,710 million compared with net after-tax expenses of $151 million for the nine months ended September 30, 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss from investments, the gain on acquisition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2019 were $3,109 million compared with $3,518 million for the nine months ended September 30, 2018.

Net earnings for the third quarter of 2019 were $1,027 million compared with $1,802 million for the third quarter of 2018 and $2,831 million for the second quarter of 2019. Net earnings for the third quarter of 2019 included net after-tax expenses of $202 million compared with net after-tax income of $448 million for the third quarter of 2018 and net after-tax income of $1,789 million for the second quarter of 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss from investments, the gain on acquisition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, adjusted net earnings from operations for the third quarter of 2019 were $1,229 million compared with $1,354 million for the third quarter of 2018 and $1,042 million for the second quarter of 2019.

Net earnings and adjusted net earnings from operations for the nine months ended September 30, 2019 compared with the nine months ended September 30, 2018 primarily reflected:

- lower realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher crude oil and NGLs sales volumes in the Exploration and Production segments;
- higher crude oil and NGLs netbacks in the North America Exploration and Production segment;
- higher crude oil and NGLs netbacks in the Offshore Africa segment; and
- higher realized foreign exchange gains.

Net earnings and adjusted net earnings from operations for the third quarter of 2019 compared with the third quarter of 2018 primarily reflected:

- lower natural gas netbacks in the North America Exploration and Production segment;
- lower realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher realized foreign exchange losses;

partially offset by:

- higher crude oil and NGLs sales volumes in the Exploration and Production segments; and
- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment.

Net earnings and adjusted net earnings from operations for the third quarter of 2019 compared with the second quarter of 2019 primarily reflected:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs sales volumes in the Exploration and Production segments;

partially offset by:

- lower realized SCO prices in the Oil Sands Mining and Upgrading segment.

Net earnings for the nine months ended September 30, 2019 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability of $1,618 million. See the "Income Taxes" section of this MD&A.

For the three and nine months ended September 30, 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings and adjusted net earnings from operations. The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings for the three and nine months ended September 30, 2019 from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the nine months ended September 30, 2019 were $6,375 million compared with $8,724 million for the nine months ended September 30, 2018. Cash flows from operating activities for the third quarter of 2019 were $2,518 million compared with $3,642 million for the third quarter of 2018 and $2,861 million for the second quarter of 2019. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings and adjusted net earnings from operations (excluding the effects of depletion, depreciation and amortization and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the nine months ended September 30, 2019 was $7,773 million compared with $7,859 million for the nine months ended September 30, 2018. Adjusted funds flow for the third quarter of 2019 was $2,881 million compared with $2,830 million for the third quarter of 2018 and $2,652 million for the second quarter of 2019. The fluctuations in adjusted funds flow from the comparable periods was primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for the nine months ended September 30, 2019 reflected an increase of $173 million related to the adoption of IFRS 16 on January 1, 2019 as the principal portion of lease payments previously classified as cash flows from operating activities is now reported as a financing activity. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

Production Volumes

Total production before royalties for the third quarter of 2019 increased 11% to 1,176,361 BOE/d from 1,060,629 BOE/d for the third quarter of 2018 and increased 15% from 1,025,800 BOE/d for the second quarter of 2019. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)		**Sep 30 2019**		Jun 30 2019		Mar 31 2019		Dec 31 2018
Product sales [1]	**$**	**6,587**	$	5,931	$	5,541	$	3,831
Crude oil and NGLs	**$**	**6,324**	$	5,597	$	5,082	$	3,327
Natural gas	**$**	**257**	$	324	$	456	$	504
Net earnings (loss)	**$**	**1,027**	$	2,831	$	961	$	(776)
Net earnings (loss) per common share								
– basic	**$**	**0.87**	$	2.37	$	0.80	$	(0.64)
– diluted	**$**	**0.87**	$	2.36	$	0.80	$	(0.64)
($ millions, except per common share amounts)		Sep 30 2018		Jun 30 2018		Mar 31 2018		Dec 31 2017
Product sales	$	6,327	$	6,389	$	5,735	$	5,516
Crude oil and NGLs	$	5,967	$	6,071	$	5,303	$	5,098
Natural gas	$	360	$	318	$	432	$	418
Net earnings (loss)	$	1,802	$	982	$	583	$	396
Net earnings (loss) per common share								
– basic	$	1.48	$	0.80	$	0.48	$	0.32
– diluted	$	1.47	$	0.80	$	0.47	$	0.32

(1) Further details related to product sales, including 'Other' income, for the three months ended September 30, 2019 are disclosed in note 17 to the Company’s unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – 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 shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"), the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the impact of the Company’s drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. 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, fluctuating capacity at the Pine River 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 volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **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, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.
- **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 impact the realized price the Company receives 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 were 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 due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
(Average for the period)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
WTI benchmark price (US$/bbl)	**$ 56.45**	$ 59.83	$ 69.50	**$ 57.06**	$ 66.79
Dated Brent benchmark price (US$/bbl)	**$ 61.85**	$ 68.36	$ 75.46	**$ 64.51**	$ 72.35
WCS heavy differential from WTI (US$/bbl)	**$ 12.24**	$ 10.65	$ 22.17	**$ 11.76**	$ 21.89
SCO price (US$/bbl)	**$ 56.87**	$ 59.96	$ 68.44	**$ 56.36**	$ 65.75
Condensate benchmark price (US$/bbl)	**$ 52.00**	$ 55.86	$ 66.82	**$ 52.79**	$ 66.28
Condensate differential from WTI (US$/bbl)	**$ 4.45**	$ 3.96	$ 2.68	**$ 4.27**	$ 0.51
NYMEX benchmark price (US$/MMBtu)	**$ 2.23**	$ 2.64	$ 2.90	**$ 2.67**	$ 2.89
AECO benchmark price (C$/GJ)	**$ 0.99**	$ 1.11	$ 1.28	**$ 1.31**	$ 1.33
US/Canadian dollar average exchange rate (US$)	**$ 0.7573**	$ 0.7474	$ 0.7651	**$ 0.7523**	$ 0.7766

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and 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. Product revenue continued to be impacted by the volatility of the 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.

Effective January 1, 2019, the Government of Alberta implemented a mandatory curtailment program that has been successful in mitigating the discount in crude oil pricing received in Alberta for both light crude oil and heavy crude oil. The timing of program cessation remains uncertain. The Company continues to execute operational flexibility to maximize production volumes through its curtailment optimization strategy, and has significant additional capacity available to further increase production volumes should curtailment restrictions ease.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.06 per bbl for the nine months ended September 30, 2019, a decrease of 15% from US$66.79 per bbl for the nine months ended September 30, 2018. WTI averaged US$56.45 per bbl for the third quarter of 2019, a decrease of 19% from US$69.50 per bbl for the third quarter of 2018, and a decrease of 6% from US$59.83 per bbl for the second quarter of 2019.

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$64.51 per bbl for the nine months ended September 30, 2019, a decrease of 11% from US$72.35 per bbl for the nine months ended September 30, 2018. Brent averaged US$61.85 per bbl for the third quarter of 2019, a decrease of 18% from US$75.46 per bbl for the third quarter of 2018, and a decrease of 10% from US$68.36 per bbl for the second quarter of 2019.

WTI and Brent pricing for the three and nine months ended September 30, 2019 has decreased from the comparable periods primarily due to increases in non-OPEC crude oil supply and decreased demand growth in Asia. In addition, global crude oil pricing has been impacted by ongoing trade disputes between the US and China.

The WCS heavy differential averaged US$11.76 per bbl for the nine months ended September 30, 2019, a decrease of 46% from US$21.89 per bbl for the nine months ended September 30, 2018. The WCS heavy differential averaged US$12.24 per bbl for the third quarter of 2019, a decrease of 45% from US$22.17 per bbl for the third quarter of 2018, and an increase of 15% from US$10.65 per bbl for the second quarter of 2019. The narrowing of the WCS heavy differential for the three and nine months ended September 30, 2019 from the comparable periods in 2018 primarily reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The widening of the differential for the third quarter of 2019 compared to the second quarter of 2019 reflected the impact of movements in US Gulf Coast benchmark pricing.

The SCO price averaged US$56.36 per bbl for the nine months ended September 30, 2019, a decrease of 14% from US$65.75 per bbl for the nine months ended September 30, 2018. The SCO price averaged US$56.87 per bbl for the third quarter of 2019, a decrease of 17% from US$68.44 per bbl for the third quarter of 2018, and a decrease of 5% from US$59.96 per bbl for the second quarter of 2019. The decrease in the SCO price for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected movement in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.67 per MMBtu for the nine months ended September 30, 2019, a decrease of 8% from US$2.89 per MMBtu for the nine months ended September 30, 2018. NYMEX natural gas prices averaged US$2.23 per MMBtu for the third quarter of 2019, a decrease of 23% from US$2.90 per MMBtu for the third quarter of 2018, and a decrease of 16% from US$2.64 per MMBtu for the second quarter of 2019.

AECO natural gas prices averaged $1.31 per GJ for the nine months ended September 30, 2019, comparable with $1.33 per GJ for the nine months ended September 30, 2018. AECO natural gas prices averaged $0.99 per GJ for the third quarter of 2019, a decrease of 23% from $1.28 per GJ for the third quarter of 2018, and a decrease of 11% from $1.11 per GJ for the second quarter of 2019.

The decrease in natural gas prices for the three and nine months ended September 30, 2019 from the comparable periods continued to reflect pipeline egress constraints out of the Basin as well as increased natural gas production in North America.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**450,662**	344,665	359,856	**372,068**	353,626
North America – Oil Sands Mining and Upgrading (1)	**432,203**	374,500	394,382	**407,695**	419,161
North Sea	**27,454**	27,594	28,702	**26,927**	24,940
Offshore Africa	**21,227**	23,650	18,802	**22,341**	18,812
	931,546	770,409	801,742	**829,031**	816,539
Natural gas (MMcf/d)					
North America	**1,425**	1,482	1,489	**1,454**	1,506
North Sea	**20**	23	38	**24**	35
Offshore Africa	**24**	27	26	**26**	27
	1,469	1,532	1,553	**1,504**	1,568
Total barrels of oil equivalent (BOE/d)	**1,176,361**	1,025,800	1,060,629	**1,079,641**	1,077,953
Product mix					
Light and medium crude oil and NGLs	**12%**	15%	13%	**14%**	13%
Pelican Lake heavy crude oil	**5%**	5%	6%	**5%**	6%
Primary heavy crude oil	**8%**	8%	9%	**7%**	8%
Bitumen (thermal oil)	**18%**	11%	11%	**13%**	10%
Synthetic crude oil	**36%**	36%	37%	**38%**	39%
Natural gas	**21%**	25%	24%	**23%**	24%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**97%**	95%	95%	**94%**	94%
Natural gas	**3%**	5%	5%	**6%**	6%

(1) SCO production before royalties excludes SCO consumed internally as diesel.

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**397,456**	307,413	307,668	**329,126**	303,833
North America – Oil Sands Mining and Upgrading	**407,592**	354,975	372,521	**386,771**	400,444
North Sea	**27,399**	27,525	28,609	**26,873**	24,873
Offshore Africa	**20,095**	22,694	17,264	**21,016**	17,467
	852,542	712,607	726,062	**763,786**	746,617
Natural gas (MMcf/d)					
North America	**1,421**	1,427	1,455	**1,416**	1,445
North Sea	**20**	23	38	**24**	35
Offshore Africa	**22**	25	22	**23**	23
	1,463	1,475	1,515	**1,463**	1,503
Total barrels of oil equivalent (BOE/d)	**1,096,329**	958,499	978,481	**1,007,669**	997,044

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 before royalties for the nine months ended September 30, 2019 averaged 829,031 bbl/d, comparable with 816,539 bbl/d for the nine months ended September 30, 2018. Crude oil and NGLs production before royalties for the third quarter of 2019 of 931,546 bbl/d increased 16% from 801,742 bbl/d for the third quarter of 2018, and increased 21% from 770,409 bbl/d for the second quarter of 2019. The increase in crude oil and NGLs production for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected production from the acquisition of thermal and heavy oil assets from Devon that closed on June 27, 2019, together with strong operational performance at both Horizon and AOSP during the third quarter of 2019 and modified timing of the Horizon turnaround schedule as a part of the Company's curtailment optimization strategy.

Third quarter 2019 crude oil and NGLs production before royalties was within the Company's previously issued guidance of 897,000 to 939,000 bbl/d. The Company's annual 2019 crude oil and NGLs production guidance remains unchanged.

Natural gas production before royalties for the nine months ended September 30, 2019 decreased 4% to 1,504 MMcf/d from 1,568 MMcf/d for the nine months ended September 30, 2018. Natural gas production for the third quarter of 2019 decreased 5% to 1,469 MMcf/d from 1,553 MMcf/d for the third quarter of 2018, and decreased 4% from 1,532 MMcf/d for the second quarter of 2019. The decrease in natural gas production for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected natural field declines.

Third quarter 2019 natural gas production before royalties exceeded the Company's previously issued guidance of 1,440 to 1,460 MMcf/d. The Company's annual 2019 natural gas production guidance remains unchanged.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the nine months ended September 30, 2019 averaged 372,068 bbl/d, an increase of 5% from 353,626 bbl/d for the nine months ended September 30, 2018. North America crude oil and NGLs production for the third quarter of 2019 of 450,662 bbl/d increased 25% from 359,856 bbl/d for the third quarter of 2018, and increased 31% from 344,665 bbl/d for the second quarter of 2019. The increase in production for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected production from the acquisition of thermal and heavy oil assets from Devon that closed on June 27, 2019 and the continued impact of the Government of Alberta mandated production curtailments that came into effect on January 1, 2019.

Pelican Lake heavy crude oil production averaged 60,146 bbl/d for the third quarter of 2019 compared with 62,727 bbl/d for the third quarter of 2018 and 55,031 bbl/d for the second quarter of 2019. Second quarter 2019 volumes reflected the temporary shut-in of crude oil production from May 30, 2019 to June 8, 2019 due to wildfires in northern Alberta.

Thermal oil production for the third quarter of 2019 averaged 206,395 bbl/d compared with 112,542 bbl/d for the third quarter of 2018 and 109,599 bbl/d for the second quarter of 2019. Thermal oil production in the third quarter of 2019 reflected volumes from the acquisition of assets from Devon. Production of thermal oil continued to reflect optimization of curtailment volumes across the Company's asset base. Third quarter 2019 thermal oil production was strong and exceeded the high end of the Company's previously issued guidance of 198,000 to 206,000 bbl/d.

Third quarter 2019 crude oil and NGLs production before royalties, including thermal oil, was within the Company's previously issued guidance of 440,000 to 458,000 bbl/d.

Natural gas production before royalties for the nine months ended September 30, 2019 decreased 3% to 1,454 MMcf/d from 1,506 MMcf/d for the nine months ended September 30, 2018. Natural gas production for the third quarter of 2019 averaged 1,425 MMcf/d, a decrease of 4% from 1,489 MMcf/d for the third quarter of 2018, and a decrease of 4% from 1,482 MMcf/d for the second quarter of 2019. The decrease in natural gas production for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the nine months ended September 30, 2019 of 407,695 bbl/d decreased 3% from 419,161 bbl/d for the nine months ended September 30, 2018. SCO production for the third quarter of 2019 increased 10% to average 432,203 bbl/d from 394,382 bbl/d for the third quarter of 2018 and increased 15% from 374,500 bbl/d for the second quarter of 2019.

The decrease in production for the nine months ended September 30, 2019 from the comparable period in 2018 primarily reflected the impact of the planned turnaround and unplanned maintenance at the non-operated Scotford Upgrader and unplanned maintenance activities at Horizon in the second quarter of 2019. The impact of turnaround and maintenance activities in the second quarter of 2019 were partially offset by strong operational performance at both Horizon and AOSP during the third quarter of 2019 and the timing of a planned turnaround at Horizon during the third quarter of 2019 compared with the prior year. The turnaround was successfully completed subsequent to September 30, 2019, on schedule and under overall cost budget. Production continues to be impacted by the Government of Alberta mandated production curtailments that came into effect on January 1, 2019. Third quarter 2019 SCO production was at the high end of the Company's previously issued guidance of 413,000 to 433,000 bbl/d.

North Sea

North Sea crude oil production before royalties for the nine months ended September 30, 2019 of 26,927 bbl/d increased 8% from 24,940 bbl/d for the nine months ended September 30, 2018. North Sea crude oil production for the third quarter of 2019 decreased 4% to 27,454 bbl/d from 28,702 bbl/d for the third quarter of 2018 and was comparable with 27,594 bbl/d for the second quarter of 2019. The increase in production for the nine months ended September 30, 2019 from the comparable period in 2018 primarily reflected volumes from new wells. The decrease in production for the three months ended September 30, 2019 from the comparable periods primarily reflected the impact of natural field declines and planned turnaround activities, partially offset by the volumes from new wells.

Offshore Africa

Offshore Africa crude oil production before royalties for the nine months ended September 30, 2019 increased 19% to 22,341 bbl/d from 18,812 bbl/d for the nine months ended September 30, 2018. Offshore Africa crude oil production for the third quarter of 2019 of 21,227 bbl/d increased 13% from 18,802 bbl/d for the third quarter of 2018 and decreased 10% from 23,650 bbl/d for the second quarter of 2019. The increase in production for the three and nine months ended September 30, 2019 from the comparable periods in 2018 primarily reflected volumes from new wells drilled in 2018 and the first quarter of 2019 at Baobab, partially offset by the cessation of production at the Olowi field in December 2018 and natural field declines. The decrease in production for the third quarter of 2019 from the second quarter of 2019 was primarily due to natural field declines.

International Guidance

Third quarter 2019 International crude oil production of 48,681 bbl/d was above the Company's previously issued guidance of 44,000 to 48,000 bbl/d.

International Crude Oil Inventory Volumes

The Company recognizes revenue on its crude oil production when control of the product passes to the customer and delivery has taken place. Revenue has not been recognized in the International business segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018
North Sea	**871,362**	969,651	881,768
Offshore Africa	**309,443**	1,076,772	868,589
	1,180,805	2,046,423	1,750,357

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs ($/bbl) [1]					
Sales price [2]	**$ 55.19**	$ 63.45	$ 57.89	**$ 57.49**	$ 54.26
Transportation	**3.69**	3.35	3.00	**3.47**	3.13
Realized sales price, net of transportation	**51.50**	60.10	54.89	**54.02**	51.13
Royalties	**6.02**	6.35	7.08	**6.11**	6.54
Production expense	**13.25**	14.42	14.47	**14.39**	15.25
Netback	**$ 32.23**	$ 39.33	$ 33.34	**$ 33.52**	$ 29.34
Natural gas ($/Mcf) [1]					
Sales price [2]	**$ 1.64**	$ 1.98	$ 2.32	**$ 2.24**	$ 2.34
Transportation	**0.40**	0.40	0.42	**0.42**	0.47
Realized sales price, net of transportation	**1.24**	1.58	1.90	**1.82**	1.87
Royalties	**0.01**	0.08	0.05	**0.07**	0.08
Production expense	**1.12**	1.23	1.33	**1.23**	1.38
Netback	**$ 0.11**	$ 0.27	$ 0.52	**$ 0.52**	$ 0.41
Barrels of oil equivalent ($/BOE) [1]					
Sales price [2]	**$ 40.36**	$ 43.38	$ 40.77	**$ 41.02**	$ 38.20
Transportation	**3.27**	2.97	2.83	**3.11**	3.03
Realized sales price, net of transportation	**37.09**	40.41	37.94	**37.91**	35.17
Royalties	**4.07**	4.06	4.44	**3.98**	4.10
Production expense	**11.11**	11.68	11.91	**11.76**	12.44
Netback	**$ 21.91**	$ 24.67	$ 21.59	**$ 22.17**	$ 18.63

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 51.51**	$ 59.45	$ 52.45	**$ 53.83**	$ 50.05
North Sea	**$ 83.64**	$ 88.25	$ 97.77	**$ 86.25**	$ 91.67
Offshore Africa	**$ 82.97**	$ 95.33	$ 98.66	**$ 86.79**	$ 96.55
Average	**$ 55.19**	$ 63.45	$ 57.89	**$ 57.49**	$ 54.26
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.51**	$ 1.84	$ 1.96	**$ 2.07**	$ 2.04
North Sea	**$ 4.67**	$ 5.34	$ 12.67	**$ 7.03**	$ 11.65
Offshore Africa	**$ 7.08**	$ 6.94	$ 7.78	**$ 7.12**	$ 7.35
Average	**$ 1.64**	$ 1.98	$ 2.32	**$ 2.24**	$ 2.34
Average ($/BOE) (1) (2)	**$ 40.36**	$ 43.38	$ 40.77	**$ 41.02**	$ 38.20

(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 8% to $53.83 per bbl for the nine months ended September 30, 2019 from $50.05 per bbl for the nine months ended September 30, 2018. North America realized crude oil prices averaged $51.51 per bbl for the third quarter of 2019, comparable with $52.45 per bbl for the third quarter of 2018, and a decrease of 13% compared with $59.45 per bbl for the second quarter of 2019. The increase in realized crude oil prices for the nine months ended September 30, 2019 from the comparable period in 2018 was primarily due to the narrowing of the WCS heavy differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The decrease in realized crude oil prices in the third quarter of 2019 from the third quarter of 2018 primarily reflected the decrease in WTI pricing, partially offset by the narrowing of the WCS heavy differential. The decrease in realized crude oil prices in the third quarter of 2019 from the second quarter of 2019 primarily reflected the decrease in WTI pricing and the widening of the WCS heavy differential. The Company continues to focus on its crude oil blending marketing strategy and in the third quarter of 2019 contributed approximately 157,100 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices averaged $2.07 per Mcf for the nine months ended September 30, 2019, comparable with $2.04 per Mcf for the nine months ended September 30, 2018. North America realized natural gas prices decreased 23% to average $1.51 per Mcf for the third quarter of 2019 from $1.96 per Mcf for the third quarter of 2018, and decreased 18% from $1.84 per Mcf for the second quarter of 2019. The decrease in realized natural gas prices for the third quarter of 2019 from the second quarter of 2019 and the third quarter of 2018 primarily reflected pipeline egress constraints out of the Basin as well as increased natural gas production in North America.

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

	Three Months Ended		
(Quarterly Average)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 48.21**	$ 53.23	$ 62.81
Pelican Lake heavy crude oil ($/bbl)	**$ 56.75**	$ 66.71	$ 54.57
Primary heavy crude oil ($/bbl)	**$ 55.47**	$ 64.71	$ 50.91
Bitumen (thermal oil) ($/bbl)	**$ 49.80**	$ 57.61	$ 43.54
Natural gas ($/Mcf)	**$ 1.51**	$ 1.84	$ 1.96

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

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

North Sea

North Sea realized crude oil prices decreased 6% to $86.25 per bbl for the nine months ended September 30, 2019 from $91.67 per bbl for the nine months ended September 30, 2018. North Sea realized crude oil prices decreased 14% to average $83.64 per bbl for the third quarter of 2019 from $97.77 per bbl for the third quarter of 2018 and decreased 5% from $88.25 per bbl for the second quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from 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 nine months ended September 30, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 10% to average $86.79 per bbl for the nine months ended September 30, 2019 from $96.55 per bbl for the nine months ended September 30, 2018. Offshore Africa realized crude oil prices decreased 16% to average $82.97 per bbl for the third quarter of 2019 from $98.66 per bbl for the third quarter of 2018 and decreased 13% from $95.33 per bbl for the second quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from 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 nine months ended September 30, 2019 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			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 6.50**	$ 6.99	$ 7.44	**$ 6.57**	$ 6.87
North Sea	**$ 0.17**	$ 0.22	$ 0.31	**$ 0.18**	$ 0.23
Offshore Africa	**$ 4.43**	$ 3.85	$ 8.07	**$ 4.77**	$ 7.72
Average	**$ 6.02**	$ 6.35	$ 7.08	**$ 6.11**	$ 6.54
Natural gas ($/Mcf) (1)					
North America	**$ 0.01**	$ 0.07	$ 0.04	**$ 0.06**	$ 0.06
Offshore Africa	**$ 0.63**	$ 0.59	$ 1.20	**$ 0.69**	$ 1.07
Average	**$ 0.01**	$ 0.08	$ 0.05	**$ 0.07**	$ 0.08
Average ($/BOE) (1)	**$ 4.07**	$ 4.06	$ 4.44	**$ 3.98**	$ 4.10

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

North America

North America crude oil and natural gas royalties for the three and nine months ended September 30, 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 12% of product sales for the nine months ended September 30, 2019 compared with 15% of product sales for the nine months ended September 30, 2018. Crude oil and NGLs royalty rates averaged approximately 13% of product sales for the third quarter of 2019 compared with 15% for the third quarter of 2018 and 12% for the second quarter of 2019. The decrease in royalty rates for the three and nine months ended September 30, 2019 from the comparable periods in 2018 primarily reflected the impact of underlying changes in the benchmark prices together with fluctuations in the WCS heavy differential.

Natural gas royalty rates averaged approximately 3% of product sales for the nine months ended September 30, 2019 compared with 4% of product sales for the nine months ended September 30, 2018. Natural gas royalty rates averaged approximately 1% of product sales for the third quarter of 2019 compared with 2% for the third quarter of 2018 and 4% for the second quarter of 2019 reflecting the decline in benchmark pricing.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 6% for the nine months ended September 30, 2019, compared with 9% of product sales for the nine months ended September 30, 2018. Royalty rates as a percentage of product sales averaged approximately 6% for the third quarter of 2019, compared with 9% of product sales for the third quarter of 2018 and 4% for the second quarter of 2019. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 11.86**	$ 13.10	$ 12.67	**$ 13.16**	$ 13.52
North Sea	**$ 37.11**	$ 37.31	$ 37.32	**$ 37.78**	$ 37.84
Offshore Africa	**$ 11.06**	$ 8.40	$ 19.53	**$ 9.87**	$ 23.03
Average	**$ 13.25**	$ 14.42	$ 14.47	**$ 14.39**	$ 15.25
Natural gas ($/Mcf) (1)					
North America	**$ 1.07**	$ 1.15	$ 1.20	**$ 1.17**	$ 1.26
North Sea (2)	**$ 3.08**	$ 5.09	$ 5.22	**$ 3.45**	$ 5.20
Offshore Africa (2)	**$ 2.78**	$ 2.49	$ 2.69	**$ 2.45**	$ 2.69
Average	**$ 1.12**	$ 1.23	$ 1.33	**$ 1.23**	$ 1.38
Average ($/BOE) (1)	**$ 11.11**	$ 11.68	$ 11.91	**$ 11.76**	$ 12.44

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

(2) North Sea and Offshore Africa natural gas production expense for the nine months ended September 30, 2019 reflected a decrease of $17 million ($2.72 per Mcf) and $4 million ($0.49 per Mcf) respectively, related to the adoption of IFRS 16.

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2019 averaged $13.16 per bbl, a decrease of 3% from $13.52 per bbl for the nine months ended September 30, 2018. North America crude oil and NGLs production expense for the third quarter of 2019 of $11.86 per bbl decreased 6% from $12.67 per bbl for the third quarter of 2018 and decreased 9% from $13.10 per bbl for the second quarter of 2019. The decrease in crude oil and NGLs production expense per barrel for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected lower energy costs, and Pelican Lake facility consolidation, along with combined synergies captured to date and higher sales volumes from the acquisition of Devon's assets. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for the nine months ended September 30, 2019 reflected a decrease of $16 million ($0.16 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for the nine months ended September 30, 2019 averaged $1.17 per Mcf, a decrease of 7% from $1.26 per Mcf for the nine months ended September 30, 2018. North America natural gas production expense for the third quarter of 2019 of $1.07 per Mcf decreased 11% from $1.20 per Mcf for the third quarter of 2018 and decreased 7% from $1.15 per Mcf for the second quarter of 2019. The decrease in production expense for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected the Company's continuous focus on cost control and achieving efficiencies across the entire asset base together with the impact of volumes processed in strategically owned and operated infrastructure.

North America natural gas production expense for the nine months ended September 30, 2019 reflected a decrease of $4 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2019 of $37.78 per bbl was comparable with $37.84 per bbl for the nine months ended September 30, 2018. North Sea crude oil production expense of $37.11 per bbl for the third quarter of 2019 was comparable with $37.32 per bbl for the third quarter of 2018 and $37.31 per bbl for the second quarter of 2019. Crude oil production expense for the three and nine months ended September 30, 2019 reflected the timing of liftings from certain fields and the underlying activity levels in the quarters as well as fluctuations in the Canadian dollar.

North Sea crude oil production expense for the nine months ended September 30, 2019 reflected a decrease of $12 million ($1.87 per bbl) related to the adoption of IFRS 16.

Offshore Africa

Offshore Africa crude oil production expense for the nine months ended September 30, 2019 was $9.87 per bbl compared with $23.03 per bbl for the nine months ended September 30, 2018. Offshore Africa crude oil production expense for the third quarter of 2019 averaged $11.06 per bbl compared with $19.53 per bbl for the third quarter of 2018 and $8.40 per bbl for the second quarter of 2019. Crude oil production expense in 2019 reflected the cessation of production at the Olowi field, Gabon in December 2018.

The fluctuations in crude oil production expense for the three and nine months ended September 30, 2019 from the comparable periods also reflected the timing of liftings from various fields that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for the nine months ended September 30, 2019 reflected a decrease of $12 million ($1.97 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense	**$ 1,021**	$ 929	$ 917	**$ 2,793**	$ 2,661
$/BOE (1)	**$ 14.89**	$ 15.60	$ 15.11	**$ 15.32**	$ 14.99

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

Depletion, depreciation and amortization expense per BOE for the nine months ended September 30, 2019 of $15.32 per BOE was comparable with $14.99 per BOE for the nine months ended September 30, 2018. Depletion, depreciation and amortization expense per BOE for the third quarter of 2019 of $14.89 per BOE was comparable with $15.11 per BOE for the third quarter of 2018 and decreased 5% from $15.60 per BOE for the second quarter of 2019.

The decrease in depletion, depreciation and amortization expense per BOE for the third quarter of 2019 from the second quarter of 2019 primarily reflected increased production volumes with lower depletion rates from the acquisition of assets from Devon in the second quarter of 2019. Depletion, depreciation and amortization expense for the nine months ended September 30, 2019 reflected an increase of $121 million ($0.66 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense	**$ 34**	$ 31	$ 31	**$ 93**	$ 94
$/BOE (1)	**$ 0.51**	$ 0.49	$ 0.52	**$ 0.51**	$ 0.53

(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 per BOE for the nine months ended September 30, 2019 decreased 4% to $0.51 per BOE from $0.53 per BOE for the nine months ended September 30, 2018. Asset retirement obligation accretion expense for the third quarter of 2019 of $0.51 per BOE was comparable with $0.52 per BOE for the third quarter of 2018, and increased 4% from $0.49 per BOE for the second quarter of 2019.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production in the third quarter of 2019 averaged 432,203 bbl/d, reflecting strong operational performance at both Horizon and AOSP. The Company successfully completed a planned turnaround at Horizon subsequent to September 30, 2019 on schedule and under overall cost budget. Production levels during the quarter continued to be impacted by the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved quarterly adjusted production costs of $736 million ($18.82 per bbl), a decrease of 10% from the second quarter of 2019 and comparable with the third quarter of 2018.

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

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
SCO realized sales price (2)	**$ 71.60**	$ 74.98	$ 81.69	**$ 70.64**	$ 77.61
Bitumen value for royalty purposes (3)	**$ 51.70**	$ 58.74	$ 51.64	**$ 52.64**	$ 43.64
Bitumen royalties (4)	**$ 3.76**	$ 3.79	$ 4.31	**$ 3.27**	$ 3.46
Transportation	**$ 1.16**	$ 1.53	$ 1.73	**$ 1.28**	$ 1.63

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $70.64 per bbl for the nine months ended September 30, 2019, a decrease of 9% from $77.61 per bbl for the nine months ended September 30, 2018. For the third quarter of 2019, the realized sales price decreased 12% to $71.60 per bbl from $81.69 per bbl for the third quarter of 2018 and decreased 5% from $74.98 per bbl for the second quarter of 2019. The decrease in the realized SCO sales price for the three and nine months ended September 30, 2019 from the comparable periods primarily reflected movements in WTI benchmark pricing.

Transportation expense for the Oil Sands Mining and Upgrading segment averaged $1.28 per bbl for the nine months ended September 30, 2019, compared with $1.63 per bbl for the nine months ended September 30, 2018. Transportation expense averaged $1.16 per bbl for the third quarter of 2019, compared with $1.73 per bbl for the third quarter of 2018 and $1.53 per bbl for the second quarter of 2019. Transportation expense for the nine months ended September 30, 2019 reflected a decrease of $55 million ($0.49 per bbl) related to the adoption of IFRS 16.

ADJUSTED 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			Nine Months Ended	
($ millions)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Production costs	**$ 784**	$ 814	$ 842	**$ 2,420**	$ 2,570
Less: costs incurred during turnaround periods	**(48)**	—	(109)	**(48)**	(109)
Adjusted production costs	**$ 736**	$ 814	$ 733	**$ 2,372**	$ 2,461
Adjusted production costs, excluding natural gas costs	**$ 721**	$ 789	$ 714	**$ 2,289**	$ 2,383
Natural gas costs	**15**	25	19	**83**	78
Adjusted production costs	**$ 736**	$ 814	$ 733	**$ 2,372**	$ 2,461

($/bbl) [1]		Three Months Ended Sep 30 2019		Jun 30 2019		Sep 30 2018		Nine Months Ended Sep 30 2019		Sep 30 2018
Adjusted production costs, excluding natural gas costs	**$**	**18.43**	$	23.45	$	19.43	**$**	**20.60**	$	20.74
Natural gas costs		**0.39**		0.72		0.52		**0.75**		0.69
Adjusted production costs	**$**	**18.82**	$	24.17	$	19.95	**$**	**21.35**	$	21.43
Sales (bbl/d)		**425,140**		369,846		399,514		**406,923**		420,790

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

Adjusted production costs for the nine months ended September 30, 2019 of $21.35 per bbl were comparable with $21.43 per bbl for the nine months ended September 30, 2018. Adjusted production costs for the third quarter of 2019 averaged $18.82 per bbl, a decrease of 6% from $19.95 per bbl for the third quarter of 2018 and a decrease of 22% from $24.17 per bbl for the second quarter of 2019. Production costs on an unadjusted basis for the three and nine months ended September 30, 2019 were $20.05 per bbl and $21.79 per bbl, respectively.

The decrease in adjusted production costs for the three and nine months ended September 30, 2019 from comparable periods reflected the Company's continuous focus on cost control and efficiencies, together with the impact of high production volumes in the third quarter of 2019, resulting from strong operational performance at both Horizon and AOSP. Production costs in the third quarter of 2019 also reflected a planned turnaround, which was successfully completed on schedule and under overall cost budget. Adjusted production costs for the nine months ended September 30, 2019 reflected a decrease of $20 million ($0.18 per bbl) related to the adoption of IFRS 16.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		Three Months Ended Sep 30 2019		Jun 30 2019		Sep 30 2018		Nine Months Ended Sep 30 2019		Sep 30 2018
Expense	**$**	**401**	$	374	$	385	**$**	**1,192**	$	1,161
Less: depreciation incurred during turnaround period		**(22)**		—		(56)		**(22)**		(56)
Adjusted depletion, depreciation and amortization	**$**	**379**	$	374	$	329	**$**	**1,170**	$	1,105
$/bbl [1]	**$**	**9.68**	$	11.12	$	8.96	**$**	**10.53**	$	9.62

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

Adjusted depletion, depreciation and amortization expense per bbl for the Oil Sands Mining and Upgrading segment for the nine months ended September 30, 2019 increased 9% to $10.53 per bbl from $9.62 per bbl for the nine months ended September 30, 2018. Adjusted depletion, depreciation and amortization expense per bbl for the third quarter of 2019 of $9.68 per bbl increased 8% from $8.96 per bbl for the third quarter of 2018, and decreased 13% from $11.12 per bbl for the second quarter of 2019.

The fluctuations in adjusted depletion, depreciation and amortization expense per barrel for the three and nine months ended September 30, 2019 from the comparable periods were primarily due to the impact of fluctuations in sales volumes from different underlying operations, along with the adoption of IFRS 16. Adjusted depletion, depreciation and amortization expense for the nine months ended September 30, 2019 reflected an increase of $65 million ($0.59 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)		Three Months Ended Sep 30 2019		Jun 30 2019		Sep 30 2018		Nine Months Ended Sep 30 2019		Sep 30 2018
Expense	**$**	**16**	$	15	$	16	**$**	**47**	$	46
$/bbl [1]	**$**	**0.38**	$	0.46	$	0.41	**$**	**0.41**	$	0.40

(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 per bbl for the nine months ended September 30, 2019 increased 3% to $0.41 per bbl from $0.40 per bbl for the nine months ended September 30, 2018. Asset retirement obligation accretion expense of $0.38 per bbl for the third quarter of 2019 decreased 7% from $0.41 per bbl for the third quarter of 2018 and decreased 17% from $0.46 for the second quarter of 2019, primarily due to higher sales volumes in the third quarter of 2019 from the comparable periods. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Revenue	**$ 21**	$ 20	$ 26	**$ 62**	$ 78
Less:					
Production expense	**4**	5	5	**15**	16
Depreciation	**4**	4	4	**11**	11
Equity loss from investment	**88**	66	2	**214**	5
Segment earnings (loss) before taxes	**$ (75)**	$ (55)	$ 15	**$ (178)**	$ 46

The Company has a 50% interest in the Redwater Partnership. Redwater Partnership has entered into agreements to construct and operate a 50,000 bbl/d bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 bbl/d of bitumen feedstock for the Company and 37,500 bbl/d 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 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing SCO into refined products. Repairs to certain stainless steel piping were substantially complete in the third quarter of 2019 and the design modifications to the reactor burners in the gasifier unit are ongoing and will continue into the first quarter of 2020. In the third quarter of 2019, the light oil refinery entered a planned maintenance shutdown targeted to be completed in December 2019. Following startup, the light oil refinery will continue to process synthetic crude feedstock until the heavy oil units can reliably commence commercial processing of bitumen. As at September 30, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at September 30, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $197 million, for a Company total of $636 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at September 30, 2019, the Company had recognized $113 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2020. As at September 30, 2019, Redwater Partnership had borrowings of $2,490 million under the syndicated credit facility.

The equity loss from investment of $214 million for the nine months ended September 30, 2019 includes the impact of $149 million of interest expense and $62 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units (nine months ended September 30, 2018 – loss of $5 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense	**$ 95**	$ 84	$ 77	**$ 249**	$ 234
$/BOE [1]	**$ 0.88**	$ 0.90	$ 0.79	**$ 0.85**	$ 0.80

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

Administration expense per BOE for the nine months ended September 30, 2019 increased 6% to $0.85 per BOE from $0.80 per BOE for the nine months ended September 30, 2018. Administration expense for the third quarter of 2019 of $0.88 per BOE increased 11% from $0.79 per BOE for the third quarter of 2018 and was comparable with $0.90 per BOE for the second quarter of 2019. Administration expense per BOE increased for the three and nine months ended September 30, 2019 from the comparable periods in 2018 primarily due to higher personnel costs, including those associated with the acquisition of assets from Devon. Administration expense for the nine months ended September 30, 2019 reflected a decrease of $18 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense (recovery)	**$ 7**	$ (7)	$ (85)	**$ 62**	$ 2

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 $62 million share-based compensation expense for the nine months ended September 30, 2019, primarily as a result of the measurement 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. Included within the share-based compensation expense for the nine months ended September 30, 2019 was $16 million related to performance share units granted to certain executive employees (September 30, 2018 – $8 million). For the nine months ended September 30, 2019, the Company charged $4 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (September 30, 2018 – $1 million recovered).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts and interest rates)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense, gross	**$ 239**	$ 214	$ 198	**$ 664**	$ 610
Less: capitalized interest	**8**	17	18	**45**	50
Expense, net	**$ 231**	$ 197	$ 180	**$ 619**	$ 560
$/BOE [1]	**$ 2.14**	$ 2.12	$ 1.85	**$ 2.11**	$ 1.92
Average effective interest rate	**3.9%**	4.1%	4.0%	**4.0%**	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 nine months ended September 30, 2019 increased from the comparable periods in 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Gross interest and other financing expense for the third quarter of 2019 was higher than the second quarter of 2019 primarily due to higher average debt levels in the third quarter as a result of the acquisition of assets from Devon that closed on June 27, 2019. Capitalized interest of $45 million for the nine months ended September 30, 2019 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the nine months ended September 30, 2019 increased 10% to $2.11 per BOE from $1.92 per BOE for the nine months ended September 30, 2018. Net interest and other financing expense per BOE for the third quarter of 2019 increased 16% to $2.14 per BOE from $1.85 per BOE for the third quarter of 2018 and was comparable with $2.12 per BOE for the second quarter of 2019. The increase in net interest and other financing expense per BOE for the three and nine months ended September 30, 2019 from the comparable periods in 2018 primarily reflected the adoption of IFRS 16, together with lower capitalized interest in 2019, and higher debt levels in 2019. Net interest and other financing expense for the nine months ended September 30, 2019 reflected an increase of $52 million ($0.18 per BOE) related to the adoption of IFRS 16.

The Company's average effective interest rate for the nine months ended September 30, 2019 increased from the nine months ended September 30, 2018 primarily due to the impact of higher benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program. The Company's average effective interest rate for the third quarter of 2019 decreased from the second quarter of 2019 as a result of lower interest rates on borrowings.

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			Nine Months Ended	
($ millions)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs financial instruments	**$ 11**	$ 13	$ —	**$ 52**	$ —
Natural gas financial instruments	**(4)**	(2)	6	**(7)**	3
Foreign currency contracts	**(8)**	16	(14)	**8**	(57)
Realized (gain) loss	**(1)**	27	(8)	**53**	(54)
Crude oil and NGLs financial instruments	**(7)**	(15)	(25)	**(17)**	(25)
Natural gas financial instruments	**7**	1	(14)	**8**	2
Foreign currency contracts	**(2)**	(2)	18	**5**	(39)
Unrealized gain	**(2)**	(16)	(21)	**(4)**	(62)
Net (gain) loss	**$ (3)**	$ 11	$ (29)	**$ 49**	$ (116)

During the nine months ended September 30, 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized gain of $4 million ($2 million after-tax) on its risk management activities for the nine months ended September 30, 2019, including an unrealized gain of $2 million ($2 million after-tax) for the third quarter of 2019 (June 30, 2019 – unrealized gain of $16 million, $13 million after-tax; September 30, 2018 – unrealized gain of $21 million, $11 million after-tax).

Further details related to outstanding derivative financial instruments at September 30, 2019 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Net realized (gain) loss	**$ (14)**	$ 2	$ 14	**$ (18)**	$ 123
Net unrealized loss (gain)	**129**	(219)	(182)	**(323)**	158
Net loss (gain) (1)	**$ 115**	$ (217)	$ (168)	**$ (341)**	$ 281

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

The net realized foreign exchange gain for the nine months ended September 30, 2019 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 nine months ended September 30, 2019 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2019 – unrealized gain of $16 million, June 30, 2019 – unrealized loss of $28 million, September 30, 2018 – unrealized loss of $23 million; nine months ended September 30, 2019 – unrealized loss of $42 million, September 30, 2018 – unrealized gain of $42 million). The US/Canadian dollar exchange rate at September 30, 2019 was US$0.7551 (June 30, 2019 – US$0.7639, September 30, 2018 – US$0.7738).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2019**	Three Months Ended Jun 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended **Sep 30 2019**	Nine Months Ended Sep 30 2018
North America [1]	**$ 133**	$ 78	$ 169	**$ 374**	$ 566
North Sea	**15**	28	12	**72**	20
Offshore Africa	**14**	11	22	**37**	43
PRT [2] – North Sea	**(4)**	(43)	(9)	**(89)**	(29)
Other taxes	**3**	3	3	**9**	8
Current income tax expense	**161**	77	197	**403**	608
Deferred corporate income tax expense (recovery)	**176**	(1,359)	145	**(1,089)**	428
Deferred PRT [2] – North Sea	**—**	1	1	**1**	18
Deferred income tax expense (recovery)	**176**	(1,358)	146	**(1,088)**	446
	337	(1,281)	343	**(685)**	1,054
Income tax rate and other legislative changes	**—**	1,618	—	**1,618**	—
	$ 337	$ 337	$ 343	**$ 933**	$ 1,054
Effective income tax rate on adjusted net earnings from operations [3]	**22%**	26%	19%	**25%**	22%

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

(2) Petroleum Revenue Tax

(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 nine months ended September 30, 2019 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 and tax rates in the countries in which the Company operates, in relation to net earnings.

The current PRT recovery in the North Sea for the three and nine months ended September 30, 2019 and the comparable periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

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

For 2019, current income tax expense is targeted to range from $450 million to $650 million in Canada and $35 million to $60 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2019	Jun 30 2019	Sep 30 2018	Nine Months Ended Sep 30 2019	Sep 30 2018
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ (2)**	$ 91	$ 41	**$ 90**	$ 39
Net expenditures	**5**	37	38	**74**	104
Total Exploration and Evaluation	**3**	128	79	**164**	143
Property, Plant and Equipment					
Net property acquisitions [2]	**30**	3,134	5	**3,188**	97
Well drilling, completion and equipping	**181**	171	416	**606**	1,087
Production and related facilities	**232**	271	325	**790**	897
Capitalized interest and other [3]	**14**	23	26	**66**	74
Total Property, Plant and Equipment	**457**	3,599	772	**4,650**	2,155
Total Exploration and Production	**460**	3,727	851	**4,814**	2,298
Oil Sands Mining and Upgrading					
Project costs [4]	**133**	106	131	**315**	260
Sustaining capital	**249**	210	173	**599**	430
Turnaround costs	**36**	17	41	**61**	100
Acquisitions of Exploration and Evaluation assets [5]	**—**	—	218	**—**	218
Capitalized interest and other [3]	**10**	9	(3)	**29**	22
Total Oil Sands Mining and Upgrading	**428**	342	560	**1,004**	1,030
Midstream and Refining	**4**	3	2	**9**	11
Abandonments [6]	**63**	41	57	**212**	197
Head office	**8**	12	3	**26**	14
Total net capital expenditures	**$ 963**	$ 4,125	$ 1,473	**$ 6,065**	$ 3,550
By segment					
North America [2]	**$ 365**	$ 3,612	$ 727	**$ 4,501**	$ 2,067
North Sea	**55**	42	35	**133**	73
Offshore Africa	**40**	73	89	**180**	158
Oil Sands Mining and Upgrading [5]	**428**	342	560	**1,004**	1,030
Midstream and Refining	**4**	3	2	**9**	11
Abandonments [6]	**63**	41	57	**212**	197
Head office	**8**	12	3	**26**	14
Total	**$ 963**	$ 4,125	$ 1,473	**$ 6,065**	$ 3,550

(1) Net capital expenditures exclude the impact of lease assets and fair value and revaluation adjustments, and include non-cash transfers of property, plant and equipment to inventory due to change in use.

(2) Includes cash consideration paid of $91 million for exploration and evaluation assets and $3,126 million for property, plant and equipment acquired from Devon in the second quarter of 2019.

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

(4) Includes Horizon Phase 2/3 construction costs.

(5) In the third quarter of 2018, total purchase consideration for the acquisition of the Joslyn oil sands project included $222 million for exploration and evaluation assets and $4 million for asset retirement obligations assumed.

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

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

($ millions)	Three Months Ended Sep 30 2019	Jun 30 2019	Sep 30 2018	Nine Months Ended Sep 30 2019	Sep 30 2018
Cash flows used in investing activities	***$ 908***	*$ 4,464*	*$ 1,265*	***$ 6,401***	*$ 3,772*
Net change in non-cash working capital [1]	***(8)***	*(380)*	*151*	***(548)***	*(391)*
Investment in other long-term assets	**—**	—	—	**—**	*(28)*
Abandonment expenditures [2]	***63***	*41*	*57*	***212***	*197*
Net capital expenditures	***$ 963***	*$ 4,125*	*$ 1,473*	***$ 6,065***	*$ 3,550*

(1) Includes net working capital and other long-term assets of $195 million related to the acquisition of assets from Devon in the second quarter of 2019.

(2) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" in the "Financial Highlights" section of this MD&A.

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 nine months ended September 30, 2019 were $6,065 million, which included $3,217 million of cash consideration paid to acquire assets from Devon in the second quarter of 2019, as compared with $3,550 million for the nine months ended September 30, 2018. Net capital expenditures for the third quarter of 2019 were $963 million, compared with $1,473 million for the third quarter of 2018 and $4,125 million for the second quarter of 2019, which included the cash consideration paid to acquire assets from Devon.

Drilling Activity [1]

(number of net wells)	Three Months Ended Sep 30 2019	Jun 30 2019	Sep 30 2018	Nine Months Ended Sep 30 2019	Sep 30 2018
Net successful natural gas wells	**5**	2	6	**15**	15
Net successful crude oil wells [2]	**36**	8	178	**74**	381
Dry wells	**—**	2	5	**3**	7
Stratigraphic test / service wells	**23**	3	47	**358**	524
Total	**64**	15	236	**450**	927
Success rate (excluding stratigraphic test / service wells)	**100%**	83%	97%	**97%**	98%

(1) Includes drilling activity for North America and International segments.

(2) Includes bitumen wells.

North America

During the third quarter of 2019, the Company targeted 5 net natural gas wells, 24 net primary heavy crude oil wells and 9 net light crude oil wells.

North Sea

During the third quarter of 2019, the Company completed 3 gross light crude oil wells (3.0 on a net basis) in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Sep 30 2019**		Jun 30 2019		Dec 31 2018		Sep 30 2018
Working capital [1]	**$**	**859**	$	709	$	(601)	$	111
Long-term debt [2] [3]	**$**	**22,489**	$	23,507	$	20,623	$	19,733
Less: cash and cash equivalents		**176**		398		101		296
Long-term debt, net	**$**	**22,313**	$	23,109	$	20,522	$	19,437
Share capital	**$**	**9,314**	$	9,320	$	9,323	$	9,393
Retained earnings		**25,382**		24,927		22,529		24,033
Accumulated other comprehensive income (loss)		**98**		27		122		(33)
Shareholders' equity	**$**	**34,794**	$	34,274	$	31,974	$	33,393
Debt to book capitalization [3] [4]		**39.1%**		40.3%		39.1%		36.8%
Debt to market capitalization [3] [5]		**34.8%**		35.4%		34.1%		27.4%
After-tax return on average common shareholders' equity [6]		**12.1%**		14.7%		8.0%		11.6%
After-tax return on average capital employed [3] [7]		**8.4%**		9.9%		5.9%		8.0%

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

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

As at September 30, 2019, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities 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, 2018. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities 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 cash flows from operating activities, 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. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - During the third quarter of 2019, the Company repaid and cancelled $800 million of the $1,800 million non-revolving term credit facility scheduled to mature in May 2020. Subsequent to September 30, 2019, the Company repaid and cancelled an additional $500 million of the remaining $1,000 million outstanding on this non-revolving term credit facility.

- During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
- Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2019, the non-revolving term credit facilities were fully drawn.
- During the second quarter of 2019, the Company extended $330 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $2,095 million outstanding under this facility continues under the previous terms and matures in June 2021.The other $2,425 million revolving credit facility matures in June 2022. Each of the $2,425 million 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 is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.
- 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 revolving bank credit facilities for amounts outstanding under this program.
- In July 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

▪ 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, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at September 30, 2019, the Company had in place revolving bank credit facilities of $4,975 million, of which $4,504 million was available. Additionally, the Company had in place fully drawn term credit facilities of $7,200 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at September 30, 2019, the Company had total US dollar denominated debt with a carrying amount of $15,399 million (US$11,628 million), before transaction costs and original issue discounts. This included $6,658 million (US$5,028 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,978 million). The fixed repayment amount of these hedging instruments is $6,415 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $243 million to $15,156 million as at September 30, 2019.

Net long-term debt was $22,313 million at September 30, 2019, resulting in a debt to book capitalization ratio of 39.1% (December 31, 2018 – 39.1%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at September 30, 2019 are discussed in note 8 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at September 30, 2019, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at September 30, 2019, 115,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for October 2019 and 102,500 GJ/d were hedged for April 2020 to October 2020. Additionally, at September 30, 2019, 95,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for November 2019 to March 2020. Further details related to the Company's commodity derivative financial instruments outstanding at September 30, 2019 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

The maturity dates of long-term debt and other long-term liabilities and related interest payments were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Long-term debt [(1)]	$	4,040	$	3,112	$	7,067	$	8,383
Other long-term liabilities [(2)]	$	273	$	205	$	435	$	1,041
Interest and other financing expense [(3)]	$	936	$	786	$	1,771	$	5,038

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $244 million; one to less than two years, $180 million; two to less than five years, $390 million; and thereafter, $1,041 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2019.

Share Capital

As at September 30, 2019, there were 1,184,206,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 54,673,000 stock options outstanding. As at November 5, 2019, the Company had 1,183,128,000 common shares outstanding and 54,032,000 stock options outstanding.

On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share, beginning with the dividend payable on April 1, 2019 (previous quarterly dividend rate of $0.335 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 21, 2019, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's NCIB approved in May 2018 expired on May 22, 2019.

For the nine months ended September 30, 2019, the Company purchased for cancellation 22,150,000 common shares at a weighted average price of $36.16 per common share for a total cost of $801 million. Retained earnings were reduced by $627 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2019, the Company purchased 1,350,000 common shares at a weighted average price of $33.70 per common share for a total cost of $45 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at September 30, 2019 [(1)]:

($ millions)		Remaining 2019		2020		2021		2022		2023		Thereafter
Product transportation [(2)]	$	177	$	719	$	688	$	615	$	502	$	4,722
North West Redwater Partnership service toll [(3)]	$	17	$	118	$	163	$	148	$	158	$	2,854
Offshore vessels and equipment	$	26	$	70	$	64	$	9	$	—	$	—
Field equipment and power	$	13	$	20	$	21	$	20	$	21	$	274
Other	$	7	$	25	$	21	$	18	$	17	$	48

(1) Subsequent to adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.

(2) On June 27, 2019, the Company assumed $2,381 million of product transportation commitments related to the acquisition of assets from Devon.

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,126 million of interest payable over the 30 year tolling period.

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. 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, including the adoption of IFRS 16 "Leases", refer to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2019.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaced IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and generally requires balance sheet recognition for all leases. Certain short-term (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

The Company adopted IFRS 16 on January 1, 2019 using the modified retrospective approach with no impact to opening retained earnings at the date of adoption. In accordance with the transitional provisions in the standard, balances reported in the comparative periods have not been restated and continue to be reported using the Company's previous accounting policy under IAS 17.

On adoption, the Company applied the following practical expedients under the standard. Certain expedients are on a lease-by-lease basis and others are applicable by class of underlying assets:

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 were treated as short-term leases;
- exclusion of initial direct costs for the measurement of lease assets at the date of initial application; and
- the application of the Company's previous assessment for onerous contracts under IAS 37, instead of re-assessing impairment on the Company's lease assets as at January 1, 2019.

The Company did not apply any practical expedients pertaining to grandfathering of leases assessed under the previous standard.

In connection with the adoption of IFRS 16, the Company recognized lease liabilities (included in other long-term liabilities) of $1,539 million, measured at the present value of the remaining lease payments, discounted at the Company’s incremental borrowing rate at the transition date. Lease assets were measured at an amount equal to the lease liability. Under the new standard, the Company reports cash outflows for payment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments is classified as cash flows from operating activities.

For further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at September 30, 2019 refer to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim financial statements for the three and nine months ended September 30, 2019.

The impacts of the adoption of IFRS 16 are discussed within the respective sections of this MD&A. The most significant impacts of the adoption of the new Leases standard are as follows:

- Cash flow from operating activities and adjusted funds flow increased as the principal portion of lease payments, previously classified as cash flows from operating activities is now reported as a financing activity;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

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 may 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, 2018.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting (“ICFR”) during the nine months ended September 30, 2019 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Based on inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.