THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2018 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2018 THIRD QUARTER RESULTS

Commenting on third quarter 2018 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "The strength of our well balanced and diverse portfolio, combined with Canadian Natural's ability to effectively and efficiently execute, delivered a strong third quarter for the Company. Record quarterly adjusted funds flow of over $2.8 billion was achieved in the third quarter and adjusted funds flow of $7.9 billion was achieved in the first nine months of 2018. Capital allocation continued to be balanced amongst our four pillars to maximize shareholder value. In the first nine months of 2018, economic resource development remained disciplined at 40% of adjusted funds flow. Returns to shareholders were robust at 26% of adjusted funds flow and 31% of adjusted funds flow was allocated to the balance sheet further strengthening our financial position. Lastly, the Company executed on minor tuck-in acquisitions, 3% of adjusted funds flow, that add optionality and significant future value.

Based on the significant progress made to date in strengthening the Company's balance sheet as well as the sustainability of Canadian Natural's free cash flow, the Board of Directors has approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, to share purchases under its Normal Course Issuer Bid (“NCIB”) and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. At present, this policy is expected to be in place until at least the Company's NCIB renewal in May 2019, subject to quarterly review by the Board of Directors. This policy is effective November 1, 2018."

Canadian Natural's President, Tim McKay, added, "Operations were strong in the third quarter of 2018 across our large, balanced and diverse asset base. The planned turnaround at our Horizon operations was successfully completed under budget and production ramped up on schedule. Our focus on effective and efficient operations resulted in strong quarterly unadjusted operating costs of $22.90/bbl (US$17.52/bbl) of Synthetic Crude Oil ("SCO") and adjusted operating costs of $19.95/bbl (US$15.26/bbl) of SCO at our Oil Sands Mining and Upgrading operations. International production volumes were strong in the quarter and exceeded previously issued Q3 guidance as a result of the successfully completed 2018 drilling program in the North Sea and strong production from a newly drilled well in Offshore Africa. Our International light crude oil volumes receive Brent pricing which averaged US$75.46/bbl in the third quarter, generating significant adjusted funds flow. Thermal in situ quarterly production volumes averaged 112,542 bbl/d, exceeding Q3/18 guidance, primarily due to the cyclical nature of steaming cycles and from production resuming following the completion of planned maintenance activities in Q2/18, as a result of proactive and strategic decisions made earlier in the year.

Canadian Natural maintains a flexible and disciplined capital allocation strategy with a focus on maintaining a strong financial position and delivering significant shareholder value. In light of current market conditions driven by market access restrictions, lack of fiscal competitiveness and regulatory uncertainties, the Company will exercise its capital flexibility and allocate capital to those areas that maximize shareholder value. Canadian Natural will continue to make strategic decisions to reduce drilling activity, delay well completions and shut in production. The effectiveness of our strategies, combined with our ability to execute on these strategies, allows us to be nimble, capture opportunities and be more sustainable through these challenges."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "In the third quarter Canadian Natural continued to deliver on its commitment to strengthen the balance sheet. The Company achieved quarterly net earnings of $1,802 million and record quarterly adjusted funds flow of $2,830 million, contributing to absolute net long-term debt reduction of approximately $2,880 million year to date. In the quarter, available liquidity improved to $5,350 million, an increase of approximately $550 million from the second quarter of 2018. Debt to adjusted EBITDA strengthened to 1.7x and debt to book capitalization improved to 36.8% over the quarter. Our focus on returns to shareholders has resulted in $2,030 million being returned to shareholders in the first nine months of 2018, by way of dividends of $1,156 million and share purchases of $874 million. Subsequent to the quarter, an additional 6,900,000 shares were purchased at a weighted average share price of $38.66. Our balance sheet strength gives us the flexibility to deliver our defined growth plan and continue to drive long-term shareholder value creation."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Sep 30 2018**	 Jun 30 2018	 Sep 30 2017	Nine Months Ended **Sep 30 2018**	 Sep 30 2017
Net earnings	**$ 1,802**	$ 982	$ 684	**$ 3,367**	$ 2,001
Per common share – basic	**$ 1.48**	$ 0.80	$ 0.56	**$ 2.75**	$ 1.72
– diluted	**$ 1.47**	$ 0.80	$ 0.56	**$ 2.74**	$ 1.71
Adjusted net earnings from operations (1)	**$ 1,354**	$ 1,279	$ 229	**$ 3,518**	$ 838
Per common share – basic	**$ 1.11**	$ 1.05	$ 0.19	**$ 2.88**	$ 0.72
– diluted	**$ 1.11**	$ 1.04	$ 0.19	**$ 2.86**	$ 0.72
Cash flows from operating activities	**$ 3,642**	$ 2,613	$ 2,522	**$ 8,724**	$ 5,824
Adjusted funds flow (2)	**$ 2,830**	$ 2,706	$ 1,675	**$ 7,859**	$ 5,040
Per common share – basic	**$ 2.32**	$ 2.20	$ 1.38	**$ 6.42**	$ 4.34
– diluted	**$ 2.31**	$ 2.19	$ 1.37	**$ 6.39**	$ 4.32
Cash flows on (from) investing activities	**$ 1,265**	$ 1,138	$ 1,960	**$ 3,772**	$ 12,028
Net capital expenditures (3)	**$ 1,473**	$ 974	$ 2,094	**$ 3,550**	$ 15,986
Daily production, before royalties					
Natural gas (MMcf/d)	**1,553**	1,539	1,664	**1,568**	1,664
Crude oil and NGLs (bbl/d)	**801,742**	793,899	759,189	**816,539**	665,399
Equivalent production (BOE/d) (4)	**1,060,629**	1,050,376	1,036,499	**1,077,953**	942,776

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

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

(3) Net capital expenditures is a non-GAAP measure that the Company considers a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. For additional information and details, refer to the net capital expenditures table in the Company's MD&A.

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

- Net earnings of $1,802 million were realized in Q3/18, an increase of $820 million and $1,118 million over Q2/18 and Q3/17 levels, respectively. Adjusted net earnings in Q3/18 of $1,354 million were achieved, a $75 million increase over Q2/18 and an increase of $1,125 million over Q3/17 levels.
- Cash flows from operating activities were $3,642 million in Q3/18, increases of $1,029 million and $1,120 million over Q2/18 and Q3/17 levels, respectively.
- Canadian Natural generated record quarterly adjusted funds flow of $2,830 million in Q3/18, increases of $124 million and $1,155 million from Q2/18 and Q3/17 levels, respectively. The increase over Q2/18 was primarily due to higher natural gas netbacks and the Company's continued focus on lowering operating costs in the Exploration and Production ("E&P") and Oil Sands Mining and Upgrading segments. The increase over Q3/17 primarily reflects higher realized prices from the Company's liquids production and higher liquids production volumes from the completion of the Horizon Phase 3 expansion.
- In Q3/18, Canadian Natural delivered significant adjusted funds flow in excess of net capital expenditures of approximately $1,360 million, including deferred discounted purchase consideration. In the first nine months of 2018, adjusted funds flow in excess of net capital expenditures, was approximately $4,310 million, including deferred discounted purchase consideration.

- After dividend requirements, free cash flow totaled approximately $950 million in Q3/18 and in the first nine months of 2018, free cash flow totaled approximately $3,150 million.
- Consistent with the Company's four pillar strategy, the Company has maintained balance in the allocation of its adjusted funds flow:
  - The Company remained disciplined in its economic resource development investments with year to date net capital expenditures of $3,196 million, excluding net acquisitions.
  - Year to date, the Company has reduced long term net debt by approximately $2,880 million, including the impact of foreign exchange, working capital and other adjustments, resulting in debt to adjusted EBITDA strengthening to 1.7x and debt to book capitalization improving to 36.8%.
  - Returns to shareholders remain a key focus for Canadian Natural as the Company has returned approximately $2,030 million in the first nine months of 2018, by way of dividends of $1,156 million and share purchases of $874 million.
    - Share purchases for cancellation totaled 9,872,600 common shares in Q3/18 at a weighted average share price of $43.81.
    - In the first nine months of 2018, share purchases totaled 20,012,727 common shares at a weighted average share price of $43.66.
    - Subsequent to quarter end and up to October 31, 2018, the Company executed additional share purchases of 6,900,000 common shares for cancellation at a weighted average share price of $38.66.
    - Subsequent to quarter end Canadian Natural declared a quarterly cash dividend on common shares of $0.335 per share payable on January 1, 2019.
  - In the first nine months of 2018, the Company has executed on opportunistic acquisitions of approximately $354 million, including Exploration and Evaluation ("E&E") expenditures of $257 million. Included in the E&E expenditures is the deferred discounted purchase consideration of $118 million, payable over the next five years. These tuck-in acquisitions add significant future value to the Company's long life low decline asset portfolio.
    - The Joslyn acquisition has the potential to add significant long life low decline reserves as well as cost savings through the extension of existing Horizon South Pit operations. The lease-line development opportunities reduce the need to relocate Horizon operations to the North Pit, to install new equipment, and construct new infrastructure. Over the next decade, synergies with Horizon are targeted to result in cost savings of over $500 million. At the Joslyn lease, the former operator had project regulatory approval for a 100,000 bbl/d project.
    - The Laricina corporate asset acquisition which includes the Grand Rapids lands is a great fit with existing lands and operations in the area. The Company's Thermal team sees the opportunity to improve the future performance of the Grand Rapids which is targeted to be piloted through the existing facilities in the future. Additionally, the Company took over operatorship of a key road needed for operations in the area, which will result in immediate savings to the Company. Canadian Natural's lands combined with the acquired lands, have total Grand Rapids bitumen in place potential of 15.9 billion barrels, adding significant future shareholder value.
  - Based on the significant progress made to date in strengthening the Company's balance sheet as well as the sustainability of Canadian Natural's free cash flow, the Board of Directors has approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, to share purchases under its Normal Course Issuer Bid ("NCIB") and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. At present, this policy is expected to be in place until at least the Company's NCIB renewal in May 2019, subject to quarterly review by the Board of Directors. This policy is effective November 1, 2018.
- The Company's production volumes in Q3/18 averaged 1,060,629 BOE/d, comparable to Q2/18 and an increase of 2% from Q3/17 levels. The increase from Q3/17 was mainly due to the completion of the Horizon Phase 3 expansion, acquisitions completed in 2017 and production from new wells in the North Sea, partially offset by declines in natural gas production along with natural gas and heavy crude oil shut ins and reduced activity of 21,500 BOE/d.
- In the first nine months of 2018, strong operating costs of $11.91/BOE were realized in the Company's E&P segment, a 7% decrease from Q2/18 levels, a significant achievement given strategic and proactive decisions to curtail, defer and shut in production during the year.

- At the Company's world class Oil Sands Mining and Upgrading assets, operations were strong and above the midpoint of guidance in Q3/18, with quarterly production of 394,382 bbl/d of Synthetic Crude Oil ("SCO"), a decrease of 3% from Q2/18 levels, as planned pit stop activities at the Athabasca Oil Sands Project ("AOSP") and a major planned turnaround at Horizon were successfully completed in the quarter. Quarterly production increased from Q3/17 levels by 11% mainly due to the production from the Horizon Phase 3 expansion.
  - Through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies, the Company realized average unadjusted operating costs of $22.90/bbl (US$17.52/bbl) of SCO in Q3/18, an impressive result given the planned downtime at Horizon in the quarter. After normalizing for planned turnaround downtime, operating costs reached $19.95/bbl (US$15.26/bbl) of SCO in Q3/18.
  - At Horizon, during the planned turnaround, optimization and reliability work on the Vacuum Distillate Unit ("VDU") furnaces and coker train was completed under budget and the units ramped up on schedule.
- At Pelican Lake, polymer flood restoration for 2018 on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood. To optimize long term oil recovery and effectiveness of the polymer flood, the Company is using modified injection parameters in the near term. As polymer flood conformance improves, the Company expects to increase oil recovery and further maximize value. In Q3/18, as a result of effective and efficient operations, strong operating costs of $6.43/bbl were achieved, an 8% decrease from Q2/18 levels and a 9% decrease from Q1/18 levels.
- Thermal in situ quarterly production volumes exceeded Q3/18 guidance, averaging 112,542 bbl/d, resulting in an increase of 7% from Q2/18 levels. The increase was primarily due to the cyclical nature of steaming cycles and from production resuming following the completion of planned maintenance in Q2/18 and proactive and strategic decisions to curtail production earlier in the year.
  - Pad additions at Primrose are ahead of schedule and on budget with initial production targeted to add approximately 10,000 bbl/d in Q4/19 and the total program is targeted to add approximately 32,000 bbl/d in 2020. These pad additions are high return activities as the Company targets to utilize available excess oil processing and steam capacity at Primrose.
  - At Kirby North, top tier execution and strong productivity has resulted in the project progressing ahead of the sanctioned schedule. Cost performance remains on budget with 80% of the Central Processing Facility complete and Steam Assisted Gravity Drainage ("SAGD") drilling nearing 70% completion. Kirby North targets to add 40,000 bbl/d of SAGD production with first oil targeted for Q4/19, one quarter earlier than originally planned.
- International E&P quarterly production volumes were strong in Q3/18, exceeding quarterly production guidance and reaching 47,504 bbl/d. International production receives Brent pricing that averaged US$75.46/bbl in Q3/18, generating significant adjusted funds flow. The increase in production of 11% and 9% from Q2/18 and Q3/17 levels respectively, was primarily due to a successful drilling program in the North Sea, partially offset by natural field declines.
  - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net production wells drilled year to date. Current light crude oil production is exceeding sanctioned expectations.
  - In Q3/18, the Company successfully drilled the first of three gross production wells at Baobab. Current light crude oil production from the first well is exceeding sanctioned expectations at approximately 2,200 bbl/d net. Subsequent to the quarter, the second well came on production with initial rates at approximately 3,700 bbl/d net. The Company is targeting the third well to come on production in Q4/18, and is on target to exceed the original budgeted production adds for the program of 5,370 bbl/d net, and as a result, Canadian Natural is currently evaluating the option to drill an additional production well in 2019, extending the drilling program at Baobab.
- Balance sheet strength and strong financial performance were demonstrated in Q3/18 through reduced long-term debt and upgraded credit ratings.
  - In Q3/18, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook.
  - In Q3/18, Canadian Natural reduced long-term net debt by approximately $1,780 million from Q2/18 levels.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances and committed bank credit facilities. At September 30, 2018 the Company had approximately $5,350 million of available liquidity, including cash and cash equivalents, an increase of approximately $550 million from Q2/18.
- Due to current market conditions driven by lack of market access for both oil and natural gas, regulatory uncertainty, and lack of fiscal competitiveness, the Company continues to exercise its capital flexibility along with proactive decisions to strategically shift capital, curtail volumes, shut in production and delay completion of recently drilled crude oil wells. These factors will play a prominent role in 2019 and future capital allocation decisions.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

Underpinning this asset base is long life low decline production from the Company's Oil Sands Mining and Upgrading, thermal in situ oil sands and Pelican Lake heavy crude oil assets. The combination of low decline, low reserve replacement cost, and effective and efficient operations means these assets provide substantial and sustainable adjusted funds flow throughout the commodity price cycle.

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

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

Drilling Activity

	Nine Months Ended Sep 30			
	2018		2017	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**402**	**381**	395	370
Natural gas	**19**	**15**	19	19
Dry	**7**	**7**	4	4
Subtotal	**428**	**403**	418	393
Stratigraphic test / service wells	**617**	**524**	238	238
Total	**1,045**	**927**	656	631
Success rate (excluding stratigraphic test / service wells)		**98%**		99%

- The Company's total crude oil and natural gas drilling program of 403 net wells for the nine months ended September 30, 2018, excluding strat/service wells, was an increase of 10 net wells from the same period in 2017. The Company's drilling levels reflect the disciplined capital allocation process and proactive actions to improve execution and control costs by balancing overall drilling levels throughout the year.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs production (bbl/d)	**247,314**	238,631	238,844	**243,857**	232,533
Net wells targeting crude oil	**140**	58	145	**299**	349
Net successful wells drilled	**135**	58	144	**292**	346
Success rate	**96%**	100%	99%	**98%**	99%

- North America crude oil and NGLs averaged 247,314 bbl/d in Q3/18, representing a 4% increase from both Q2/18 and Q3/17 levels. The volume increase from Q2/18 was primarily a result of increased production in primary heavy crude oil due to the ramp up of new wells previously curtailed and increased production in light crude oil due to the additional capital allocated from primary heavy crude oil, partially offset by curtailed primary heavy crude oil production volumes. The increase from Q3/17 was mainly due to the successful integration of acquired assets at Pelican Lake.
- Due to widening price differentials driven by market access restrictions, the Company made the proactive and strategic decision to shut in, curtail and reduce activity on heavy crude oil production resulting in production impacts of approximately 10,000 bbl/d to 15,000 bbl/d in October and approximately 45,000 bbl/d to 55,000 bbl/d targeted for November and December.
- Canadian Natural's primary heavy crude oil production averaged 91,631 bbl/d in Q3/18, an 8% increase from Q2/18 levels primarily due to ramp up of new wells previously curtailed along with a full quarter of production at the Company's Smith primary heavy crude oil play.
  - In Q3/18, to maximize value as a result of widening price differentials, Canadian Natural continued to implement and execute proactive decisions and strategic actions to allocate more capital from primary heavy crude oil assets to light crude oil assets. As a result, the Company drilled 63 less net wells in Q3/18, with a year to date impact of 83 less net primary heavy crude oil wells in the year than originally budgeted. Additionally, in Q3/18, the Company delayed completion on 33 net primary heavy crude oil wells as well as shut in production. The Company targets to bring on the delayed and shut in production when primary heavy crude oil netbacks improve.
  - At the Company's Smith primary heavy crude oil play, production results continue to be strong from the 6 net multilateral wells on production with current rates of approximately 300 bbl/d per well, which are exceeding original production expectations of 171 bbl/d from sanction. Additionally, actual decline rates are coming in significantly lower than sanctioned rates. There is significant potential at Smith for future development as Canadian Natural has 19 net sections in the fairway with the potential to add approximately 125 net horizontal multilateral primary heavy crude oil wells.
  - Controlling costs remains a focus with operating costs of $15.58/bbl in Q3/18, an 8% decrease from Q2/18 levels, due to increased volumes from previously curtailed primary heavy crude oil production.
- North America light crude oil and NGL quarterly production averaged 92,956 bbl/d, an increase of 3% from Q2/18 levels and comparable to Q3/17 levels. The increase from Q2/18 is primarily as a result of a successful drilling program and increased production in light crude oil due to the additional capital allocated from primary heavy crude oil, partially offset by natural declines.
  - The Company successfully drilled 27 net light crude oil wells in Q3/18, 19 net wells above the original plan as the Company reallocated capital from primary heavy crude oil to light crude oil. Highlights from wells coming on production to date are as follows:
    - At Wembley, production remains strong at approximately 500 bbl/d per well from wells drilled earlier in 2018. With this success, an additional 4 net wells were drilled in Q3/18 with production targeted to come on in Q4/18. The Company has 77 net Montney sections of lands in the area with greater than 175 potential premium light crude oil well locations.
      - Including the greater Wembley area, the Company has an additional 54 net Montney sections and over 125 incremental potential premium light crude oil well locations.
    - In Southeast Saskatchewan, the Company drilled 9 net light crude oil wells in Q3/18 with some wells on production late in the quarter and the remaining wells are targeting to come on production in Q4/18. These light crude oil wells were drilled as a result of the strategic decision to shift capital to light crude oil and were not originally budgeted. Additionally, production from these Saskatchewan wells are less impacted by the apportionment issues and price differentials experienced in Alberta.
  - At the Company's light crude oil development at Tower, operations are currently ramping up with 6 out of 7 net wells on production, and current facility constrained production averaging approximately 5,500 BOE/d due to gas handling at capacity at the facility. With the positive results on the first wells, the Company has 11 net sections with the potential for an additional 41 net wells that would leverage off the existing facility over time, adding significant value.
  - Operating costs of $15.51/bbl were realized in Q3/18, a decrease of 2% from Q2/18 levels in the Company's light crude oil and NGL areas.

- Pelican Lake quarterly production averaged 62,727 bbl/d, comparable with Q2/18 levels and an increase of 32% from Q3/17 levels. The increase from Q3/17 was as a result of the Company's successful integration of acquired assets in late 2017.
  - Polymer flood restoration for 2018 on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood. To optimize long term oil recovery and effectiveness of the polymer flood, the Company is using modified injection parameters in the near term. As polymer flood conformance improves, the Company expects to increase oil recovery and further maximize value.
  - Strong operating costs of $6.43/bbl were achieved in Q3/18, an 8% decrease from Q2/18 levels and a 9% decrease from Q1/18 levels.
- The Company’s 2018 North America E&P crude oil and NGL annual production guidance is targeted to range between 240,000 bbl/d - 246,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Bitumen production (bbl/d)	**112,542**	104,907	122,372	**109,769**	118,798
Net wells targeting bitumen	**41**	21	10	**84**	22
Net successful wells drilled	**41**	21	10	**84**	22
Success rate	**100%**	100%	100%	**100%**	100%

- Thermal in situ quarterly production volumes exceeded Q3/18 guidance, averaging 112,542 bbl/d, resulting in an increase of 7% from Q2/18 levels. The increase was primarily due to the cyclical nature of steaming cycles and from production resuming following the completion of planned maintenance in Q2/18 and proactive and strategic decisions to curtail production earlier in the year.
  - At Primrose, Q3/18 production volumes averaged 72,500 bbl/d, an increase of 7% from Q2/18 levels, primarily as a result of the timing of cyclical steaming where additional wells entered the production cycle. Including energy costs, operating costs were strong at $11.80/bbl in Q3/18, a decrease of 20% from Q2/18 levels.
    - Pad additions at Primrose are ahead of schedule and on budget with initial production targeted to add an approximate 10,000 bbl/d in Q4/19 and the total program is targeted to add approximately 32,000 bbl/d in 2020. These pad additions are high return activities as the Company targets to utilize available excess oil processing and steam capacity at Primrose.
  - At Kirby South, SAGD production volumes of 35,839 bbl/d were achieved in Q3/18, comparable to Q2/18 and a 4% decrease from Q3/17 levels. Including energy costs, Kirby South achieved strong Q3/18 operating costs of $9.14/bbl, comparable to Q2/18 and a 2% increase from Q3/17 levels.
  - At Kirby North, top tier execution and strong productivity has resulted in the project progressing ahead of the sanctioned schedule. Cost performance remains on budget with 80% of the Central Processing Facility complete and SAGD drilling nearing 70% completion. Kirby North targets to add 40,000 bbl/d of SAGD production with first oil targeted for Q4/19, one quarter earlier than originally planned.
- The Company’s 2018 thermal in situ annual production guidance remains unchanged and is targeted to range between 107,000 bbl/d - 127,000 bbl/d.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Natural gas production (MMcf/d)	**1,489**	1,485	1,593	**1,506**	1,602
Net wells targeting natural gas	**6**	4	3	**15**	20
Net successful wells drilled	**6**	4	3	**15**	19
Success rate	**100%**	100%	100%	**100%**	95%

- North America natural gas production was as expected at 1,489 MMcf/d in Q3/18, comparable to Q2/18 and a decrease of 7% from Q3/17 levels. The decrease from Q3/17 was primarily due to strategic decisions made to reduce drilling and development activities and shut in production as a result of low natural gas prices and third party facility constraints.
- Operating costs of $1.20/Mcf were realized in Q3/18, a decrease of 6% from Q2/18 levels, strong results given lower natural gas production volumes due to the Company's proactive decision to shut in volumes and delay activity on certain natural gas assets.
- In 2018, the Company continues to make proactive and strategic decisions to maximize value in the Company's natural gas assets and as a result, Q3/18 production volumes were reduced by approximately 146 MMcf/d due to the following:
  - Deferred capital and development activity including recompletions and workovers of certain natural gas assets along with production shut ins, resulted in a production impact of approximately 96 MMcf/d in Q3/18. The Company targets to re-evaluate these development activities when natural gas prices improve.
  - Q3/18 production was impacted by approximately 8 MMcf/d related to solution gas associated with the curtailment of primary heavy crude oil production.
  - Additionally, the Company's natural gas production capability was reduced by approximately 42 MMcf/d in Q3/18 due to restrictions at the Pine River plant, operated by a third party. The third party completed the planned four week turnaround from mid-September to mid-October, but due to additional integrity issues, the plant is now targeting to start up in mid-November. During the turnaround, Canadian Natural was able to assess the potential for the plant to be restored to match the field capacity of 145 MMcf/d. The Company is evaluating the work that would be required and will decide on an investment decision as part of its 2019 budget process. As previously announced, Canadian Natural agreed to acquire the facility from the third party and is waiting for regulatory approval.
- In Q3/18, Canadian Natural used natural gas in its operations representing approximately 37% of its total equivalent gas production providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 28% of the total natural gas production is exported to other North American markets at an average Q3/18 price of $3.26/GJ or sold internationally at a Q3/18 average price of $11.31/GJ. The remaining 35% of the Company's production is exposed to AECO/Station 2 pricing.
- The Company’s 2018 corporate natural gas annual production guidance remains unchanged and is targeted to range between 1,550 MMcf/d - 1,600 MMcf/d.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil production (bbl/d)					
North Sea	**28,702**	24,456	24,832	**24,940**	24,733
Offshore Africa	**18,802**	18,201	18,776	**18,812**	20,610
Natural gas production (MMcf/d)					
North Sea	**38**	30	46	**35**	40
Offshore Africa	**26**	24	25	**27**	22
Net wells targeting crude oil	**1.6**	1.9	-	**4.5**	1.8
Net successful wells drilled	**1.6**	1.9	-	**4.5**	1.8
Success rate	**100%**	100%	-	**100%**	100%

- International E&P quarterly production volumes were strong in Q3/18, exceeding quarterly production guidance and reaching 47,504 bbl/d which receives Brent pricing that averaged US$75.46/bbl in Q3/18, generating significant adjusted funds flow. The increase in production of 11% and 9% from Q2/18 and Q3/17 levels respectively, was primarily due to a successful drilling program in the North Sea, partially offset by natural field declines.
  - In the North Sea, production volumes of 28,702 bbl/d were achieved in Q3/18, an increase of 17% and 16% over Q2/18 and Q3/17 levels respectively, primarily due to the successful drilling program completed in 2018 and partially offset by planned maintenance activities at Ninian South during the quarter.
    - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net producer wells drilled year to date. Current light crude oil production is exceeding sanctioned expectations.
    - The Company's continued focus on production enhancements, increased reliability and water flood optimization in the North Sea resulted in Q3/18 operating costs of $37.32/bbl.
    - For Q4/18, the Company has planned turnaround and maintenance activities in the North Sea at Ninian Central and Tiffany.
  - Offshore Africa production volumes in Q3/18 averaged 18,802 bbl/d, an increase of 3% from Q2/18 and comparable to Q2/17 levels. The increase from Q2/18 was primarily as a result of production resuming following the planned maintenance activities completed during Q2/18, together with new production from the first of three gross production wells planned at Baobab.
    - Côte d'Ivoire crude oil operating costs in Q3/18 were strong at $13.94/bbl, a 15% decrease from Q2/18 levels.
    - In Q3/18, the Company successfully drilled the first of three gross production wells at Baobab. Current light crude oil production from the first well is exceeding sanctioned expectations at approximately 2,200 bbl/d net. Subsequent to the quarter, the second well came on production with initial rates at approximately 3,700 bbl/d net. The Company is targeting the third well to come on production in Q4/18, and is on target to exceed the original budgeted production adds for the program of 5,370 bbl/d net, and as a result, Canadian Natural is currently evaluating the option to drill an additional production well in 2019, extending the drilling program at Baobab.
    - In Q4/18, the Company has planned maintenance activities in Côte d'Ivoire at the Espoir Floating Production Storage and Offloading vessel.
    - Subsequent to the quarter, the Company farmed out a 25% working interest in the Exploration Right relating to Block 11B/12B located offshore South Africa. The Operator has secured a drilling unit to re-enter an exploration well on the Block with drilling operations targeted to commence during the first quarter of 2019.
      - As part of the farm out, Canadian Natural received an up front cash consideration and will also receive a material financial carry on the exploration well costs and subsequent operations. Subject to there being a commercial discovery, the Company will receive further bonus payments.

  - The transaction was completed on October 29. Canadian Natural's working interest in the Block is now 25%.
- The Company's 2018 International annual production guidance remains unchanged and is targeted to range from 40,000 bbl/d - 45,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Synthetic crude oil production (bbl/d) (1) (2)	**394,382**	407,704	354,365	**419,161**	268,725

(1) Q3/18 SCO production before royalties excludes 2,758 bbl/d of SCO consumed internally as diesel (Q2/18 – 3,026 bbl/d; Q3/17 – 0 bbl/d).

(2) Consists of heavy and light synthetic crude oil products.

- At the Company's world class Oil Sands Mining and Upgrading assets, operations were strong and above the midpoint of guidance in Q3/18 with quarterly production of 394,382 bbl/d of SCO, a decrease of 3% from Q2/18 levels, as planned pit stop activities at the AOSP and a major planned turnaround at Horizon were successfully completed in the quarter. Quarterly production increased from Q3/17 levels by 11% mainly due to the production from the Horizon Phase 3 expansion.
  - Through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies, the Company realized average unadjusted operating costs of $22.90/bbl (US$17.52/bbl) of SCO in Q3/18, an impressive result given the planned downtime at Horizon in the quarter. After normalizing for planned turnaround downtime, operating costs reached $19.95/bbl (US$15.26/bbl) of SCO in Q3/18.
  - At Horizon, during the planned turnaround, optimization and reliability work on the VDU furnaces and coker train was completed under budget and the units ramped up on schedule.
  - The Company continues to evaluate the previously announced potential expansion opportunities at Horizon to increase reliability, lower costs and potentially add targeted production of 75,000 bbl/d to 95,000 bbl/d. The engineering and design specification work is on track, targeting to be substantially completed by year end.
  - The Company's 2018 Oil Sands Mining and Upgrading capital guidance is targeted to be $200 million less than previously announced. The reduction in capital in 2018 is primarily due to deferral of capital spend and achieved cost savings related to strategic capital projects.
- The Company's 2018 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range between 415,000 bbl/d - 450,000 bbl/d of upgraded products.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 69.50**	$ 67.90	$ 48.19	**$ 66.79**	$ 49.43
WCS heavy differential as a percentage of WTI (%) (2)	**32%**	28%	21%	**33%**	24%
SCO price (US$/bbl)	**$ 68.44**	$ 67.27	$ 48.83	**$ 65.75**	$ 50.03
Condensate benchmark pricing (US$/bbl)	**$ 66.82**	$ 68.85	$ 47.96	**$ 66.28**	$ 49.52
Average realized pricing before risk management (C$/bbl) (3)	**$ 57.89**	$ 61.14	$ 46.33	**$ 54.26**	$ 46.82
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.28**	$ 0.97	$ 1.94	**$ 1.33**	$ 2.45
Average realized pricing before risk management (C$/Mcf)	**$ 2.32**	$ 1.95	$ 2.29	**$ 2.34**	$ 2.83

(1) West Texas Intermediate ("WTI").
(2) Western Canadian Select ("WCS").
(3) Average crude oil and NGL pricing excludes SCO. Pricing is net of blending costs and excluding risk management activities.

- In Q3/18, the WCS heavy differential widened as a result of a shortage of export pipeline capacity out of the Western Canadian Sedimentary Basin resulting in higher apportionment on the Enbridge Mainline system.
  - Canadian Natural and other industry participants, as part of a working committee, are working towards a more effective nomination process that verifies actual production and sales. Having an effective nomination process is significant to Canadian Natural as the Company is required to sell portions of its heavy crude oil production at a discount to the WCS index as a result of apportionment on the Enbridge pipeline.
- AECO natural gas prices for Q3/18 continued to reflect third party pipeline constraints limiting flow of natural gas to export markets, increased natural gas production in the basin and constraints on export capacity out of Western Canada. The increase in natural gas prices for Q3/18 from Q2/18 levels reflected the easing of third party pipeline constraints as well as seasonal demand factors.
- The North West Redwater ("NWR") refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by creating incremental demand for approximately 80,000 bbl/d of heavy crude oil blends that will not require export pipelines, helping to reduce pricing volatility in all Western Canadian heavy crude oil.
  - The North West Redwater refinery began processing light crude oil in November 2017 and commissioning continues for the start up of bitumen processing in Q4/18.
  - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

ENVIRONMENTAL HIGHLIGHTS

In Q2/18 Canadian Natural published its 2017 Stewardship Report to Stakeholders, now available on the Company's website at https://www.cnrl.com/corporate-responsibility/stewardship-report/#2017. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint.

- Canadian Natural has invested significant capital to capture and sequester CO_2. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford and carbon capture facilities at its 50% interest through the NWR refinery. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 570,000 vehicles off the road, making the Company the 5th largest capturer and sequester of CO_2 globally once the NWR refinery is fully running.
- At Canadian Natural's Oil Sands operations, which represent approximately 66% of the Company's liquids production, the Company's emissions intensity is only approximately 5% higher than the average intensity for all global crude

oils. By investing in and leveraging technology, specifically carbon capture initiatives, Canadian Natural has developed a pathway to reduce the Company's greenhouse gas ("GHG") emissions intensity to below the average for global crude oils.

- Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by its In Pit Extraction Process ("IPEP") pilot at Horizon, which will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's carbon emissions and environmental footprint by reducing the usage of haul trucks, the size and need for tailings ponds and accelerating site reclamation. In addition this process has the potential to significantly reduce capital and operating costs.
  - Initial results from the Company's IPEP pilot have been positive with excellent recovery rates and evidence of stackable tailings. As a result, the Company will continue running the pilot through the winter.
- The Company’s GHG emissions intensity has decreased materially by 18% from 2013 to 2017.
- Methane emissions have decreased 71% from 2013 to 2017 at the Company's Alberta primary heavy crude oil operations.

FINANCIAL REVIEW

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

- The Company’s strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production levels of 1,060,629 BOE/d in Q3/18, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with current approximate product mix on a BOE/d basis of 50% light crude oil and SCO blends, 25% heavy crude oil blends and 25% natural gas, based upon the midpoint of annual 2018 production guidance.
  - Canadian Natural’s production is resilient, as long life low decline assets make up approximately 72% of 2018 liquids production guidance, including the AOSP, Horizon, Pelican Lake and thermal in situ oil sands assets.
- In Q3/18, Canadian Natural delivered significant adjusted funds flow in excess of net capital expenditures of approximately $1,360 million, including deferred purchase consideration. In the first nine months of 2018, adjusted funds flow in excess of net capital expenditures was approximately $4,310 million, including deferred purchase consideration.
- Balance sheet strength and strong financial performance were demonstrated in Q3/18 through reduced long-term debt and upgraded credit ratings.
  - Overall Canadian Natural reduced long-term net debt by approximately $1,780 million from Q2/18 levels and approximately $3,170 million from Q3/17 levels.
  - In Q3/18, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook.
  - In Q3/18, the Company utilized adjusted funds flow to repay and cancel $1,050 million of the $2,850 million non-revolving term loan facility; $1,800 million remains outstanding and fully drawn.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At September 30, 2018 the Company had approximately $5,350 million of available liquidity, including cash and cash equivalents, an increase of approximately $550 million from Q2/18.
  - As at September 30, 2018, debt to book capitalization improved to 36.8% from 39.6% in Q2/18 and debt to adjusted EBITDA strengthened to 1.7x from 2.1x in Q2/18.
- Returns to shareholders remain a key focus for Canadian Natural as the Company has returned approximately $2,030 million by way of dividends of $1,156 million and share purchases of $874 million in the first nine months of 2018.
  - Share purchases for cancellation totaled 9,872,600 common shares in the quarter at a weighted average share price of $43.81.

- In the first nine months of 2018, share purchases totaled 20,012,727 common shares at a weighted average share price of $43.66.
- Subsequent to quarter end and up to October 31, 2018, the Company had additional share purchases of 6,900,000 common shares for cancellation at a weighted average share price of $38.66.

▪ Based on the significant progress made to date in strengthening the Company's balance sheet as well as the sustainability of Canadian Natural's free cash flow, the Board of Directors has approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, to share purchases under its NCIB and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. At present, this policy is expected to be in place until at least the Company's NCIB renewal in May 2019, subject to quarterly review by the Board of Directors. This policy is effective November 1, 2018.

▪ In addition to its strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at September 30, 2018, these financial levers include the Company's third party equity investments of approximately $658 million.

▪ Subsequent to quarter end, Canadian Natural declared a quarterly cash dividend on common shares of $0.335 per share payable on January 1, 2019.

CORPORATE UPDATE

▪ One of Canadian Natural's many strengths is the depth and strength of our management team and our ability to develop people and execute succession plans. Subject to Board of Directors approval, it is anticipated that, effective March 31, 2019, the following changes will take effect:

- Corey B. Bieber, Senior Vice-President Finance and Chief Financial Officer will become Executive Advisor, Finance. Corey will remain on the Management Committee and continue to work together with the Finance, Investor Relations, Information Systems, Legal and International teams.
- In recognition of the fact that Canadian Natural has grown significantly and the business environment has become more complex, in addition to maintaining the office of the Chief Financial Officer, Management believes it is appropriate to add the role of Principal Accounting Officer. This will facilitate even stronger leadership, depth of expertise and financial discipline.
- Mark Stainthorpe, Vice President – Capital Markets, will assume the role of Chief Financial Officer and Senior Vice President, Finance and will join the Management Committee. Mark has accumulated over 16 years of experience at Canadian Natural with progressive responsibilities in various accounting departments, Treasury and Investor Relations. Mark will have overall responsibility for the finance functions at Canadian Natural.
- Ron Kim, Vice President, Finance – Corporate will assume the role of Principal Accounting Officer and Vice President, Finance, reporting to Mark Stainthorpe. Ron joined Canadian Natural in 2006 and has held various roles and progressive responsibilities. Ron's most recent responsibilities included oversight of taxation, corporate accounting and financial reporting. Ron will be responsible for overseeing accounting policy, processes and financial reporting of the Company.

OUTLOOK

The Company forecasts annual 2018 production levels to average between 802,000 and 868,000 bbl/d of crude oil and NGLs and between 1,550 and 1,600 MMcf/d of natural gas, before royalties. Q4/18 production guidance before royalties is forecast to average between 801,000 and 849,000 bbl/d of crude oil and NGLs and between 1,480 and 1,510 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Canadian Natural's annual 2018 capital expenditures are targeted to be approximately $4.6 billion.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, 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") operations and future expansions, the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the cost and timing of construction 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 or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations and the assumption of operations at processing facilities also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital 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 material adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company's estimates or opinions change.

Management's Discussion and Analysis

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

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, 2018 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). 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); net capital expenditures; adjusted cash production costs and adjusted depreciation, depletion and amortization. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, and cash flows from 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. 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 from investing activities, as determined in accordance with IFRS, in the "Net capital expenditures" section of this MD&A. The derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights - Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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

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

The following discussion and analysis refers primarily to the Company's financial results for the three and nine months ended September 30, 2018 in relation to the comparable periods in 2017 and the second quarter of 2018. 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, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. This MD&A is dated October 31, 2018.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2018	Jun 30 2018	Sep 30 2017	Nine Months Ended Sep 30 2018	Sep 30 2017
Product sales	**$ 6,327**	$ 6,389	$ 4,725	**$ 18,451**	$ 12,844
Crude oil and NGLs	**$ 5,967**	$ 6,071	$ 4,320	**$ 17,341**	$ 11,424
Natural gas	**$ 360**	$ 318	$ 405	**$ 1,110**	$ 1,420
Net earnings	**$ 1,802**	$ 982	$ 684	**$ 3,367**	$ 2,001
Per common share – basic	**$ 1.48**	$ 0.80	$ 0.56	**$ 2.75**	$ 1.72
– diluted	**$ 1.47**	$ 0.80	$ 0.56	**$ 2.74**	$ 1.71
Adjusted net earnings from operations (1)	**$ 1,354**	$ 1,279	$ 229	**$ 3,518**	$ 838
Per common share – basic	**$ 1.11**	$ 1.05	$ 0.19	**$ 2.88**	$ 0.72
– diluted	**$ 1.11**	$ 1.04	$ 0.19	**$ 2.86**	$ 0.72
Cash flows from operating activities	**$ 3,642**	$ 2,613	$ 2,522	**$ 8,724**	$ 5,824
Adjusted funds flow (2)	**$ 2,830**	$ 2,706	$ 1,675	**$ 7,859**	$ 5,040
Per common share – basic	**$ 2.32**	$ 2.20	$ 1.38	**$ 6.42**	$ 4.34
– diluted	**$ 2.31**	$ 2.19	$ 1.37	**$ 6.39**	$ 4.32
Cash flows on (from) investing activities	**$ 1,265**	$ 1,138	$ 1,960	**$ 3,772**	$ 12,028
Net capital expenditures (3)	**$ 1,473**	$ 974	$ 2,094	**$ 3,550**	$ 15,986

(1) 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 certain items of a non-operational nature. The Company considers adjusted net earnings from operations a key measure in evaluating the Company's performance. The reconciliation "Adjusted Net Earnings from Operations" presented in this MD&A, presents the after-tax effects of certain items of a non-operational nature that are included in the Company's financial results. Adjusted net earnings from operations may not be comparable to similar measures presented by other companies.

(2) 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, and abandonment and other expenditures. The Company evaluates its performance based on adjusted funds flow. The Company considers adjusted funds flow a key measure as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented below in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(3) Net capital expenditures is a non-GAAP measure that represents cash flows from 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 acquisitions 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 from Investing Activities" is presented in the Net Capital Expenditures section of this MD&A on page 25. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings from Operations

($ millions)	Three Months Ended Sep 30 2018	Three Months Ended Jun 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Net earnings	***$ 1,802***	*$ 982*	*$ 684*	***$ 3,367***	*$ 2,001*
Share-based compensation, net of tax (1)	***(85)***	*175*	*114*	***2***	*37*
Unrealized risk management gain, net of tax (2)	***(11)***	*(11)*	*(6)*	***(53)***	*(35)*
Unrealized foreign exchange (gain) loss, net of tax (3)	***(182)***	*178*	*(404)*	***158***	*(819)*
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	***—***	*—*	*—*	***146***	*—*
Loss (gain) from investments, net of tax (5) (6)	***89***	*38*	*(76)*	***240***	*(7)*
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	***(259)***	*(83)*	*(83)*	***(342)***	*(339)*
Adjusted net earnings from operations	***$ 1,354***	*$ 1,279*	*$ 229*	***$ 3,518***	*$ 838*

(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 (gain) from investments is the Company's pro rata share of the Redwater Partnership's accounting loss (gain) 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. Further details related to the acquisitions are discussed in notes 4 and 5 of the Company's unaudited interim consolidated financial statements. 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 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. During the third quarter of 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During the second quarter of 2017, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.

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

($ millions)	Three Months Ended Sep 30 2018	Three Months Ended Jun 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Cash flows from operating activities	***$ 3,642***	*$ 2,613*	*$ 2,522*	***$ 8,724***	*$ 5,824*
Net change in non-cash working capital	***(889)***	*57*	*(918)*	***(1,067)***	*(1,008)*
Abandonment expenditures	***57***	*50*	*65*	***197***	*211*
Other (2)	***20***	*(14)*	*6*	***5***	*13*
Adjusted funds flow	***$ 2,830***	*$ 2,706*	*$ 1,675*	***$ 7,859***	*$ 5,040*

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

(2) Includes non-cash movements in other long-term assets and is primarily related to the unamortized costs of the share bonus program.

SUMMARY OF CONSOLIDATED NET EARNINGS, CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

Net earnings for the nine months ended September 30, 2018 were $3,367 million compared with net earnings of $2,001 million for the nine months ended September 30, 2017. Net earnings for the nine months ended September 30, 2018 included net after-tax expenses of $151 million compared with net after-tax income of $1,163 million for the nine months ended September 30, 2017 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 (gain) from investments, and the gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the nine months ended September 30, 2018 were $3,518 million compared with adjusted net earnings of $838 million for the nine months ended September 30, 2017.

Net earnings for the third quarter of 2018 were $1,802 million compared with net earnings of $684 million for the third quarter of 2017 and net earnings of $982 million for the second quarter of 2018. Net earnings for the third quarter of 2018 included net after-tax income of $448 million compared with net after-tax income of $455 million for the third quarter of 2017 and net after-tax expenses of $297 million for the second quarter of 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) from investments, and the gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the third quarter of 2018 were $1,354 million compared with adjusted net earnings of $229 million for the third quarter of 2017 and adjusted net earnings of $1,279 million for the second quarter of 2018.

The increase in adjusted net earnings for the three and nine months ended September 30, 2018 from the three and nine months ended September 30, 2017 was primarily due to:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- higher realized risk management gains;

partially offset by:

- higher depletion, depreciation and amortization in the Oil Sands Mining and Upgrading segment;
- lower crude oil and NGLs sales volumes in the Exploration and Production segments; and
- lower natural gas netbacks in the North America Exploration and Production segment.

Adjusted net earnings for the third quarter of 2018 increased 6% from the second quarter of 2018 primarily due to higher natural gas netbacks in the Exploration and Production segments and the impact of lower production and transportation, blending and feedstock expenses, partially offset by the impact of lower realized crude oil and NGLs prices in the North America Exploration and Production segment.

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

Cash flows from operating activities for the nine months ended September 30, 2018 were $8,724 million compared with $5,824 million for the nine months ended September 30, 2017. Cash flows from operating activities for the third quarter of 2018 were $3,642 million compared with $2,522 million for the third quarter of 2017 and $2,613 million for the second quarter of 2018. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (except for the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the nine months ended September 30, 2018 were $7,859 million compared with $5,040 million for the nine months ended September 30, 2017. Adjusted funds flow for the third quarter of 2018 were $2,830 million compared with $1,675 million for the third quarter of 2017 and $2,706 million for the second quarter of 2018. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in adjusted net earnings (except for the effect of depletion, depreciation and amortization), as well as due to the impact of fluctuations in cash taxes.

Total production before royalties for the third quarter of 2018 increased 2% to 1,060,629 BOE/d from 1,036,499 BOE/d for the third quarter of 2017 and was comparable with 1,050,376 BOE/d for the second quarter of 2018.

SUMMARY OF QUARTERLY RESULTS

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

($ millions, except per common share amounts)		**Sep 30 2018**		Jun 30 2018		Mar 31 2018		Dec 31 2017
Product sales [1]	**$**	**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	**$**	**1,802**	$	982	$	583	$	396
Net earnings per common share								
– basic	**$**	**1.48**	$	0.80	$	0.48	$	0.32
– diluted	**$**	**1.47**	$	0.80	$	0.47	$	0.32

($ millions, except per common share amounts)		Sep 30 2017		Jun 30 2017		Mar 31 2017		Dec 31 2016
Product sales [1]	$	4,725	$	4,127	$	3,992	$	3,672
Crude oil and NGLs	$	4,320	$	3,645	$	3,459	$	3,193
Natural gas	$	405	$	482	$	533	$	479
Net earnings	$	684	$	1,072	$	245	$	566
Net earnings per common share								
– basic	$	0.56	$	0.93	$	0.22	$	0.51
– diluted	$	0.56	$	0.93	$	0.22	$	0.51

(1) Comparative figures for product sales in 2016 are reported in accordance with the Company's presentation prior to adoption of IFRS 15 on January 1, 2018. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15.

Volatility in the quarterly net earnings 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 and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, new production from Horizon Phase 2B and Phase 3, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, shut-in production due to low commodity prices, and the impact of the drilling program in the International segments. 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 a third-party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production, the impact of seasonal costs that are dependent on weather, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds at Horizon.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses 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 include 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 gains on the acquisition of AOSP and other assets, 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) in Redwater Partnership.

BUSINESS ENVIRONMENT

	Three Months Ended			Nine Months Ended	
(Average for the period)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
WTI benchmark price (US$/bbl)	**$ 69.50**	$ 67.90	$ 48.19	**$ 66.79**	$ 49.43
Dated Brent benchmark price (US$/bbl)	**$ 75.46**	$ 74.51	$ 51.76	**$ 72.35**	$ 52.01
WCS heavy differential from WTI (US$/bbl)	**$ 22.17**	$ 19.24	$ 9.94	**$ 21.89**	$ 11.86
SCO price (US$/bbl)	**$ 68.44**	$ 67.27	$ 48.83	**$ 65.75**	$ 50.03
Condensate benchmark price (US$/bbl)	**$ 66.82**	$ 68.85	$ 47.96	**$ 66.28**	$ 49.52
NYMEX benchmark price (US$/MMBtu)	**$ 2.90**	$ 2.80	$ 3.00	**$ 2.89**	$ 3.16
AECO benchmark price (C$/GJ)	**$ 1.28**	$ 0.97	$ 1.94	**$ 1.33**	$ 2.45
US/Canadian dollar average exchange rate (US$)	**$ 0.7651**	$ 0.7746	$ 0.7983	**$ 0.7766**	$ 0.7649

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 in 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.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$66.79 per bbl for the nine months ended September 30, 2018, an increase of 35% from US$49.43 per bbl for the nine months ended September 30, 2017. WTI averaged US$69.50 per bbl for the third quarter of 2018, an increase of 44% from US$48.19 per bbl for the third quarter of 2017, and an increase of 2% from US$67.90 per bbl for the second quarter of 2018.

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$72.35 per bbl for the nine months ended September 30, 2018, an increase of 39% from US$52.01 per bbl for the nine months ended September 30, 2017. Brent averaged US$75.46 per bbl for the third quarter of 2018, an increase of 46% from US$51.76 per bbl for the third quarter of 2017, and comparable with US$74.51 per bbl for the second quarter of 2018.

WTI and Brent pricing for the three and nine months ended September 30, 2018 has increased from the comparable periods due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil.

The WCS heavy differential averaged US$21.89 per bbl for the nine months ended September 30, 2018, an increase of 85% from US$11.86 per bbl for the nine months ended September 30, 2017. The WCS heavy differential averaged US$22.17 per bbl for the third quarter of 2018, an increase of 123% from US$9.94 per bbl for the third quarter of 2017, and an increase of 15% from US$19.24 per bbl for the second quarter of 2018. The widening of the WCS heavy differential for the three and nine months ended September 30, 2018 from the comparable periods reflected a shortage of export pipeline capacity out of the Western Canadian Sedimentary Basin resulting in higher apportionment on the Enbridge Mainline system.

The SCO price averaged US$65.75 per bbl for the nine months ended September 30, 2018, an increase of 31% from US$50.03 per bbl for the nine months ended September 30, 2017. The SCO price averaged US$68.44 per bbl for the third quarter of 2018, an increase of 40% from US$48.83 per bbl for the third quarter of 2017, and an increase of 2% from US$67.27 per bbl for the second quarter of 2018. The increase in SCO pricing for the three and nine months ended September 30, 2018 from the comparable periods was primarily due to changes in WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.89 per MMBtu for the nine months ended September 30, 2018, a decrease of 9% from US$3.16 per MMBtu for the nine months ended September 30, 2017. NYMEX natural gas prices averaged US$2.90 per MMBtu for the third quarter of 2018, a decrease of 3% from US$3.00 per MMBtu for the third quarter of 2017, and an increase of 4% from US$2.80 per MMBtu for the second quarter of 2018.

AECO natural gas prices averaged $1.33 per GJ for the nine months ended September 30, 2018, a decrease of 46% from $2.45 per GJ for the nine months ended September 30, 2017. AECO natural gas prices averaged $1.28 per GJ for the third quarter of 2018, a decrease of 34% from $1.94 per GJ for the third quarter of 2017, and an increase of 32% from $0.97 per GJ for the second quarter of 2018.

The decrease in natural gas prices for the three and nine months ended September 30, 2018 from the comparable periods in 2017 continued to reflect third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin. The increase in natural gas prices for the third quarter of 2018 compared with the second quarter of 2018 reflected the easing of third party pipeline constraints as well as seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**359,856**	343,538	361,216	**353,626**	351,331
North America – Oil Sands Mining and Upgrading [1]	**394,382**	407,704	354,365	**419,161**	268,725
North Sea	**28,702**	24,456	24,832	**24,940**	24,733
Offshore Africa	**18,802**	18,201	18,776	**18,812**	20,610
	801,742	793,899	759,189	**816,539**	665,399
Natural gas (MMcf/d)					
North America	**1,489**	1,485	1,593	**1,506**	1,602
North Sea	**38**	30	46	**35**	40
Offshore Africa	**26**	24	25	**27**	22
	1,553	1,539	1,664	**1,568**	1,664
Total barrels of oil equivalent (BOE/d)	**1,060,629**	1,050,376	1,036,499	**1,077,953**	942,776
Product mix					
Light and medium crude oil and NGLs	**13%**	13%	13%	**13%**	14%
Pelican Lake heavy crude oil	**6%**	6%	5%	**6%**	5%
Primary heavy crude oil	**9%**	8%	10%	**8%**	10%
Bitumen (thermal oil)	**11%**	10%	11%	**10%**	13%
Synthetic crude oil	**37%**	39%	34%	**39%**	29%
Natural gas	**24%**	24%	27%	**24%**	29%
Percentage of gross revenue [1] [2] (excluding Midstream revenue)					
Crude oil and NGLs	**95%**	95%	92%	**94%**	89%
Natural gas	**5%**	5%	8%	**6%**	11%

(1) Third quarter 2018 SCO production before royalties excludes 2,758 bbl/d of SCO consumed internally as diesel (second quarter 2018 – 3,026 bbl/d; third quarter 2017 – 0 bbl/d; nine months ended September 30, 2018 – 3,001 bbl/d; nine months ended September 30, 2017 – 287 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**307,668**	293,080	310,497	**303,833**	305,084
North America – Oil Sands Mining and Upgrading	**372,521**	385,986	345,067	**400,444**	262,528
North Sea	**28,609**	24,411	24,784	**24,873**	24,683
Offshore Africa	**17,264**	16,502	17,735	**17,467**	19,543
	726,062	719,979	698,083	**746,617**	611,838
Natural gas (MMcf/d)					
North America	**1,455**	1,407	1,543	**1,445**	1,525
North Sea	**38**	30	46	**35**	40
Offshore Africa	**22**	20	22	**23**	19
	1,515	1,457	1,611	**1,503**	1,584
Total barrels of oil equivalent (BOE/d)	**978,481**	962,742	966,528	**997,044**	875,831

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

Crude oil and NGLs production for the nine months ended September 30, 2018 increased 23% to 816,539 bbl/d from 665,399 bbl/d for the nine months ended September 30, 2017. Crude oil and NGLs production for the third quarter of 2018 of 801,742 bbl/d increased 6% from 759,189 bbl/d for the third quarter of 2017, and was comparable with 793,899 bbl/d in the second quarter of 2018. The increase in crude oil and NGLs production for the three and nine months ended September 30, 2018 from the comparable periods in 2017 was primarily due to the impact of Phase 3 production at Horizon, acquisitions completed in 2017, and production from new wells in the North Sea, partially offset by the impact of proactive measures taken to delay completion and ramp up of new wells in thermal and heavy oil in the first half of 2018.

Third quarter 2018 crude oil and NGLs production was above the midpoint of the Company's previously issued guidance of 771,000 to 819,000 bbl/d. Fourth quarter 2018 crude oil and NGLs production guidance is targeted to average between 801,000 and 849,000 bbl/d. Annual 2018 crude oil and NGLs production guidance is now targeted to average between 802,000 and 868,000 bbl/d.

Natural gas production for the nine months ended September 30, 2018 decreased 6% to 1,568 MMcf/d from 1,664 MMcf/d for the nine months ended September 30, 2017. Natural gas production for the third quarter of 2018 averaged 1,553 MMcf/d, a decrease of 7% from 1,664 MMcf/d for the third quarter of 2017, and comparable with 1,539 MMcf/d for the second quarter of 2018. Natural gas production in the third quarter of 2018 as compared with the second quarter of 2018 reflected the Company’s reliable and efficient operations following the planned maintenance activities in the second quarter of 2018, partially offset by the impact of the strategic deferral of natural gas activities due to low natural gas prices and natural field declines. The decrease in production for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected reduced natural gas activity, including the impact of shut-in volumes as a result of low natural gas prices together with natural field declines.

Third quarter 2018 natural gas production was within the Company's previously issued guidance of 1,535 to 1,565 MMcf/d. Fourth quarter 2018 natural gas production guidance is targeted to average between 1,480 and 1,510 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the nine months ended September 30, 2018 averaged 353,626 bbl/d, comparable with 351,331 bbl/d for the nine months ended September 30, 2017. North America crude oil and NGLs production for the third quarter of 2018 of 359,856 bbl/d was comparable with 361,216 bbl/d for the third quarter of 2017, and increased 5% from 343,538 bbl/d for the second quarter of 2018. The increase in production for the third quarter of 2018 from the second quarter of 2018 primarily reflected strong performance in thermal oil, exceeding the Company's third quarter production guidance. Strong production was due to the cyclic nature of thermal production, together with production resuming following the planned maintenance activities at various facilities during the second quarter of 2018. The third quarter of 2018 also reflected increased heavy oil production due to the ramp up of new wells that had been previously curtailed.

Operating performance at Pelican Lake continued to be strong following the acquisition completed in 2017, leading to production of 62,727 bbl/d in the third quarter of 2018 compared with 47,604 bbl/d in the third quarter of 2017 and 63,914 bbl/d in the second quarter of 2018. The polymer flood on the acquired Pelican assets has been restored to 62% of the field, ahead of schedule, with all 2018 work now complete.

Overall thermal oil production for the third quarter of 2018 averaged 112,542 bbl/d compared with 122,372 bbl/d for the third quarter of 2017 and 104,907 bbl/d for the second quarter of 2018. Third quarter 2018 thermal oil production exceeded the Company's previously issued guidance of 106,000 to 112,000 bbl/d. Fourth quarter 2018 thermal oil production guidance is targeted to average between 96,000 and 102,000 bbl/d.

Third quarter 2018 crude oil and NGLs production, including thermal oil, was within the Company's previously issued guidance of 354,000 to 368,000 bbl/d. Fourth quarter 2018 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 328,000 and 342,000 bbl/d. Annual 2018 crude oil and NGLs production guidance, including thermal oil, is now targeted to average between 347,000 and 373,000 bbl/d.

Natural gas production for the nine months ended September 30, 2018 decreased 6% to 1,506 MMcf/d from 1,602 MMcf/d for the nine months ended September 30, 2017. Natural gas production for the third quarter of 2018 averaged 1,489 MMcf/d, a decrease of 7% from 1,593 MMcf/d for the third quarter of 2017, and comparable with 1,485 MMcf/d in the second quarter of 2018. Natural gas production in the third quarter of 2018 as compared with the second quarter of 2018 reflected the Company’s reliable and efficient operations following the planned maintenance activities in the second quarter of 2018, partially offset by the impact of the strategic deferral of natural gas activities due to low natural gas prices and natural field declines. The decrease in production for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected reduced natural gas activity, including the impact of shut-in volumes as a result of low natural gas prices together with natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production for the nine months ended September 30, 2018 of 419,161 bbl/d increased 56% from 268,725 bbl/d for the nine months ended September 30, 2017. SCO production for the third quarter of 2018 increased 11% to average 394,382 bbl/d from 354,365 bbl/d for the third quarter of 2017 and decreased 3% from 407,704 bbl/d for the second quarter of 2018. The increase in SCO production for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected the impact of Phase 3 production at Horizon and production from the acquisition of AOSP. Production in the third quarter of 2018 was strong following the planned maintenance activities in the second quarter of 2018 and the successful completion of the planned turnaround at Horizon during the third quarter of 2018. The decrease in the third quarter of 2018 from the second quarter of 2018 reflected lower production volumes during the turnaround period.

Third quarter 2018 SCO production was above the midpoint of the Company's previously issued guidance of 374,000 to 404,000 bbl/d. Fourth quarter 2018 SCO production guidance is targeted to average between 433,000 and 463,000 bbl/d.

North Sea

North Sea crude oil production for the nine months ended September 30, 2018 of 24,940 bbl/d was comparable with 24,733 bbl/d for the nine months ended September 30, 2017. North Sea crude oil production for the third quarter of 2018 increased 16% to 28,702 bbl/d from 24,832 bbl/d for the third quarter of 2017 and increased 17% from 24,456 bbl/d in the second quarter of 2018. The increase in production for the third quarter of 2018 from the comparable periods primarily reflected the successful drilling program completed in 2018, partially offset by planned maintenance activities at Ninian South during the third quarter of 2018.

Offshore Africa

Offshore Africa crude oil production for the nine months ended September 30, 2018 decreased 9% to 18,812 bbl/d from 20,610 bbl/d for the nine months ended September 30, 2017. Offshore Africa crude oil production for the third quarter of 2018 of 18,802 bbl/d was comparable with 18,776 bbl/d for the third quarter of 2017 and increased 3% from 18,201 bbl/d in the second quarter of 2018. The decrease in production for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 primarily reflected natural field declines. The increase in production for the third quarter of 2018 from the second quarter of 2018 primarily reflected production resuming following the planned maintenance activities completed during the second quarter of 2018, together with new production from the first well of three gross production wells planned at Baobab.

International Guidance

Third quarter 2018 International crude oil production of 47,504 bbl/d exceeded the Company's previously issued guidance of 43,000 to 47,000 bbl/d. Fourth quarter 2018 International crude oil production guidance is targeted to average between 40,000 and 44,000 bbl/d, reflecting the impact of the planned maintenance activities in the North Sea and Offshore Africa.

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 that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017
North Sea	**881,768**	297,217	506,748
Offshore Africa	**868,589**	1,466,074	639,622
	1,750,357	1,763,291	1,146,370

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 57.89**	$ 61.14	$ 46.33	**$ 54.26**	$ 46.82
Transportation	**3.00**	3.30	2.81	**3.13**	2.79
Realized sales price, net of transportation	**54.89**	57.84	43.52	**51.13**	44.03
Royalties	**7.08**	7.56	5.33	**6.54**	5.03
Production expense	**14.47**	15.64	14.71	**15.25**	14.84
Netback	**$ 33.34**	$ 34.64	$ 23.48	**$ 29.34**	$ 24.16
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.32**	$ 1.95	$ 2.29	**$ 2.34**	$ 2.83
Transportation	**0.42**	0.51	0.33	**0.47**	0.37
Realized sales price, net of transportation	**1.90**	1.44	1.96	**1.87**	2.46
Royalties	**0.05**	0.08	0.07	**0.08**	0.12
Production expense	**1.33**	1.39	1.22	**1.38**	1.25
Netback (3)	**$ 0.52**	$ (0.03)	$ 0.67	**$ 0.41**	$ 1.09
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 40.77**	$ 41.63	$ 33.27	**$ 38.20**	$ 34.40
Transportation	**2.83**	3.20	2.51	**3.03**	2.59
Realized sales price, net of transportation	**37.94**	38.43	30.76	**35.17**	31.81
Royalties	**4.44**	4.75	3.36	**4.10**	3.28
Production expense	**11.91**	12.75	11.73	**12.44**	11.83
Netback	**$ 21.59**	$ 20.93	$ 15.67	**$ 18.63**	$ 16.70

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended September 30, 2018 was $1.05/Mcfe (three months ended June 30, 2018 - $0.60/Mcfe, three months ended September 30, 2017 - $0.96/Mcfe).

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 52.45**	$ 56.95	$ 43.56	**$ 50.05**	$ 44.16
North Sea	**$ 97.77**	$ 93.49	$ 66.07	**$ 91.67**	$ 67.04
Offshore Africa	**$ 98.66**	$ 102.57	$ 64.14	**$ 96.55**	$ 64.78
Company average	**$ 57.89**	$ 61.14	$ 46.33	**$ 54.26**	$ 46.82
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.96**	$ 1.69	$ 2.07	**$ 2.04**	$ 2.66
North Sea	**$ 12.67**	$ 10.32	$ 7.73	**$ 11.65**	$ 7.76
Offshore Africa	**$ 7.78**	$ 7.37	$ 6.56	**$ 7.35**	$ 6.52
Company average	**$ 2.32**	$ 1.95	$ 2.29	**$ 2.34**	$ 2.83
Company average ($/BOE) (1) (2)	**$ 40.77**	$ 41.63	$ 33.27	**$ 38.20**	$ 34.40

(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 13% to $50.05 per bbl for the nine months ended September 30, 2018 from $44.16 per bbl for the nine months ended September 30, 2017. North America realized crude oil prices averaged $52.45 per bbl for the third quarter of 2018, an increase of 20% compared with $43.56 per bbl for the third quarter of 2017, and a decrease of 8% compared with $56.95 per bbl for the second quarter of 2018. The increase in realized crude oil prices for the three and nine months ended September 30, 2018 from the comparable periods in 2017 was primarily due to higher WTI benchmark pricing, partially offset by the widening of the WCS heavy differential. The decrease in realized crude oil prices for the third quarter of 2018 from the second quarter of 2018 was primarily due to 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 2018 contributed approximately 167,700 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 23% to average $2.04 per Mcf for the nine months ended September 30, 2018 from $2.66 per Mcf for the nine months ended September 30, 2017. North America realized natural gas prices decreased 5% to average $1.96 per Mcf for the third quarter of 2018 compared with $2.07 per Mcf for the third quarter of 2017, and increased 16% compared with $1.69 per Mcf for the second quarter of 2018. The decrease in realized natural gas prices for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected third party pipeline constraints limiting flow of natural gas to export markets. The increase in realized natural gas prices for the third quarter of 2018 from the second quarter of 2018 primarily reflected the easing of third party pipeline constraints as well as seasonal demand factors.

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

(Quarterly Average)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 62.81**	$ 62.06	$ 43.27
Pelican Lake heavy crude oil ($/bbl)	**$ 54.57**	$ 60.49	$ 45.67
Primary heavy crude oil ($/bbl)	**$ 50.91**	$ 56.33	$ 45.55
Bitumen (thermal oil) ($/bbl)	**$ 43.54**	$ 51.04	$ 41.38
Natural gas ($/Mcf)	**$ 1.96**	$ 1.69	$ 2.07

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

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

North Sea

North Sea realized crude oil prices increased 37% to average $91.67 per bbl for the nine months ended September 30, 2018 from $67.04 per bbl for the nine months ended September 30, 2017. North Sea realized crude oil prices increased 48% to average $97.77 per bbl for the third quarter of 2018 from $66.07 per bbl for the third quarter of 2017 and increased 5% from $93.49 per bbl for the second quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and nine months ended September 30, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 49% to average $96.55 per bbl for the nine months ended September 30, 2018 from $64.78 per bbl for the nine months ended September 30, 2017. Offshore Africa realized crude oil prices increased 54% to average $98.66 per bbl for the third quarter of 2018 from $64.14 per bbl for the third quarter of 2017 and decreased 4% from $102.57 per bbl for the second quarter of 2018. Realized crude oil prices per bbl in any particular year are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and nine months ended September 30, 2018 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 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 7.44**	$ 8.03	$ 5.84	**$ 6.87**	$ 5.50
North Sea	**$ 0.31**	$ 0.17	$ 0.13	**$ 0.23**	$ 0.13
Offshore Africa	**$ 8.07**	$ 9.58	$ 3.56	**$ 7.72**	$ 3.37
Company average	**$ 7.08**	$ 7.56	$ 5.33	**$ 6.54**	$ 5.03
Natural gas ($/Mcf) (1)					
North America	**$ 0.04**	$ 0.06	$ 0.05	**$ 0.06**	$ 0.12
Offshore Africa	**$ 1.20**	$ 1.17	$ 0.95	**$ 1.07**	$ 0.73
Company average	**$ 0.05**	$ 0.08	$ 0.07	**$ 0.08**	$ 0.12
Company average ($/BOE) (1)	**$ 4.44**	$ 4.75	$ 3.36	**$ 4.10**	$ 3.28

(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, 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalties averaged approximately 15% of product sales for the nine months ended September 30, 2018 compared with 13% of product sales for the nine months ended September 30, 2017. Crude oil and NGLs royalties averaged approximately 15% of product sales for the third quarter of 2018 compared with 14% for the third quarter of 2017 and 15% for the second quarter of 2018. The increase in royalties for the three and nine months ended September 30, 2018 from the comparable periods in 2017 was primarily due to higher realized crude oil prices.

Natural gas royalties averaged approximately 4% of product sales for the nine months ended September 30, 2018 compared with 5% of product sales for the nine months ended September 30, 2017. Natural gas royalties averaged approximately 2% of product sales for the third quarter of 2018 compared with 3% for the third quarter of 2017 and 5% for the second quarter of 2018. The decrease in royalties for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected lower realized natural gas prices. The decrease in royalties for the third quarter of 2018 from the second quarter of 2018 primarily reflected the impact of royalty adjustments in both periods.

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 9% for the nine months ended September 30, 2018, compared with 6% of product sales for the nine months ended September 30, 2017. Royalty rates as a percentage of product sales averaged approximately 9% for the third quarter of 2018, compared with 6% of product sales for the third quarter of 2017 and 10% for the second quarter of 2018. Royalties 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 2018	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.67**	$ 13.78	$ 12.10	**$ 13.52**	$ 12.66
North Sea	**$ 37.32**	$ 35.12	$ 35.72	**$ 37.84**	$ 34.06
Offshore Africa	**$ 19.53**	$ 24.78	$ 29.24	**$ 23.03**	$ 26.39
Company average	**$ 14.47**	$ 15.64	$ 14.71	**$ 15.25**	$ 14.84
Natural gas ($/Mcf) (1)					
North America	**$ 1.20**	$ 1.28	$ 1.15	**$ 1.26**	$ 1.17
North Sea	**$ 5.22**	$ 5.81	$ 3.09	**$ 5.20**	$ 3.18
Offshore Africa	**$ 2.69**	$ 3.00	$ 2.32	**$ 2.69**	$ 3.13
Company average	**$ 1.33**	$ 1.39	$ 1.22	**$ 1.38**	$ 1.25
Company average ($/BOE) (1)	**$ 11.91**	$ 12.75	$ 11.73	**$ 12.44**	$ 11.83

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

North America

North America crude oil and NGLs production expense for the nine months ended September 30, 2018 increased 7% to $13.52 per bbl from $12.66 per bbl for the nine months ended September 30, 2017. North America crude oil and NGLs production expense for the third quarter of 2018 of $12.67 per bbl increased 5% from $12.10 per bbl in the third quarter of 2017 and decreased 8% from $13.78 per bbl for the second quarter of 2018. Crude oil and NGLs production expense for the three and nine months ended September 30, 2018 as compared with the periods in 2017 primarily reflected the Company's continuous focus on cost control and achieving efficiencies on acquired assets and across the entire asset base partially offsetting significantly increased carbon tax and energy costs in 2018. The decrease per barrel for the third quarter of 2018 from the second quarter of 2018 reflected higher volumes and lower service costs, together with the Company's continuous focus on cost control.

North America natural gas production expense for the nine months ended September 30, 2018 averaged $1.26 per Mcf, an increase of 8% from $1.17 per Mcf for the nine months ended September 30, 2017. North America natural gas production expense for the third quarter of 2018 increased 4% to $1.20 per Mcf from $1.15 per Mcf for the third quarter of 2017 and decreased 6% from $1.28 per Mcf for the second quarter of 2018. Natural gas production expense for the three and nine months ended September 30, 2018 as compared with the periods in 2017 primarily reflected the Company's continuous focus on cost control and achieving efficiencies on acquired assets and across the entire asset base partially offsetting the impact of lower volumes on a relatively fixed cost base. The decrease in natural gas production expense for the third quarter of 2018 from the second quarter of 2018 primarily reflected lower service costs.

North Sea

North Sea crude oil production expense for the nine months ended September 30, 2018 increased 11% to $37.84 per bbl from $34.06 per bbl for the nine months ended September 30, 2017. North Sea crude oil production expense for the third quarter of 2018 increased 4% to $37.32 per bbl from $35.72 per bbl for the third quarter of 2017 and increased 6% from $35.12 per bbl in the second quarter of 2018. The increase in crude oil production expense for the three and nine months ended September 30, 2018 from the comparable periods in 2017 primarily reflected higher carbon tax costs in 2018, along with higher recoveries realized in the second quarter of 2017. The increase in production expense for the third quarter of 2018 from the second quarter of 2018 primarily reflected the timing of liftings from various fields that have different cost structures and higher fuel and carbon tax costs, partially offset by increased production. Production expense is also impacted by movements in the Canadian dollar.

Offshore Africa

Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire for the nine months ended September 30, 2018 was $14.05 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $23.03 per bbl. Production expense for the third quarter of 2018 relating to Côte d'Ivoire was $13.94 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $19.53 per bbl. Total Offshore Africa crude oil production expense for the three and nine months ended September 30, 2018 primarily reflected the timing of liftings from various fields, including the Olowi field, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned maintenance activities, and fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Expense	**$ 917**	$ 894	$ 945	**$ 2,661**	$ 3,018
$/BOE (1)	**$ 15.11**	$ 15.20	$ 14.87	**$ 14.99**	$ 16.30

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

Depletion, depreciation and amortization per BOE for the nine months ended September 30, 2018 decreased 8% to $14.99 per BOE from $16.30 per BOE for the nine months ended September 30, 2017. Depletion, depreciation and amortization expense per BOE for the third quarter of 2018 of $15.11 per BOE was comparable with $14.87 per BOE for the third quarter of 2017 and $15.20 per BOE for the second quarter of 2018.

The decrease in depletion, depreciation and amortization expense per BOE for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 was primarily due to additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Expense	**$ 31**	$ 32	$ 29	**$ 94**	$ 86
$/BOE (1)	**$ 0.52**	$ 0.53	$ 0.47	**$ 0.53**	$ 0.47

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

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

Asset retirement obligation accretion expense for the nine months ended September 30, 2018 increased 13% to $0.53 per BOE from $0.47 per BOE for the nine months ended September 30, 2017. Asset retirement obligation accretion expense for the third quarter of 2018 increased 11% to $0.52 per BOE from $0.47 per BOE for the third quarter of 2017, and decreased 2% from $0.53 per BOE for the second quarter of 2018.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and to leverage its expertise to capture synergies following the acquisition completed in 2017. Production averaged 394,382 bbl/d during the third quarter of 2018, reflecting the successful completion of the turnaround during the quarter and steady and reliable operations following the maintenance activities completed during the second quarter of 2018. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, adjusted cash production costs averaged $19.95 per bbl during the quarter.

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

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
SCO realized sales price (2)	**$ 81.69**	$ 80.17	$ 56.55	**$ 77.61**	$ 61.33
Bitumen value for royalty purposes (3)	**$ 51.64**	$ 49.10	$ 40.69	**$ 43.64**	$ 39.45
Bitumen royalties (4)	**$ 4.31**	$ 4.25	$ 1.39	**$ 3.46**	$ 1.33
Transportation	**$ 1.73**	$ 1.63	$ 1.61	**$ 1.63**	$ 1.42

(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 $77.61 per bbl for the nine months ended September 30, 2018, an increase of 27% from $61.33 per bbl for the nine months ended September 30, 2017. For the third quarter of 2018, the realized sales price increased 44% to $81.69 per bbl from $56.55 per bbl for the third quarter of 2017 and increased 2% from $80.17 per bbl for the second quarter of 2018. The increase in realized sales prices for the three and nine months ended September 30, 2018 from the comparable periods primarily reflected WTI benchmark pricing.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Cash production costs	**$ 842**	$ 855	$ 829	**$ 2,570**	$ 1,754
Less: costs incurred during turnaround periods	**(109)**	—	(79)	**(109)**	(79)
Adjusted cash production costs	**$ 733**	$ 855	$ 750	**$ 2,461**	$ 1,675
Adjusted cash production costs, excluding natural gas costs	**$ 714**	$ 834	$ 717	**$ 2,383**	$ 1,571
Natural gas costs	**19**	21	33	**78**	104
Adjusted cash production costs	**$ 733**	$ 855	$ 750	**$ 2,461**	$ 1,675

	Three Months Ended			Nine Months Ended	
($/bbl) (1)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Adjusted cash production costs, excluding natural gas costs	**$ 19.43**	$ 22.37	$ 21.68	**$ 20.74**	$ 21.37
Natural gas costs	**0.52**	0.57	1.01	**0.69**	1.42
Adjusted cash production costs	**$ 19.95**	$ 22.94	$ 22.69	**$ 21.43**	$ 22.79
Sales (bbl/d)	**399,514**	409,603	359,748	**420,790**	269,317

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

Adjusted cash production costs for the nine months ended September 30, 2018 decreased 6% to $21.43 per bbl from $22.79 per bbl for the nine months ended September 30, 2017. Adjusted cash production costs for the third quarter of 2018 averaged $19.95 per bbl, a decrease of 12% from $22.69 per bbl for the third quarter of 2017 and a decrease of 13% from $22.94 per bbl for the second quarter of 2018. The decrease in adjusted cash production costs per barrel for the three and nine months ended September 30, 2018 from the comparable periods primarily reflected the Company's high utilization rates and reliability, and its ability to capture cost synergies, together with additional capacity from Phase 3 production at Horizon and the acquisition of AOSP.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Expense	**$ 385**	$ 372	$ 324	**$ 1,161**	$ 756
Less: depreciation incurred during turnaround period	**(56)**	—	(25)	**(56)**	(25)
Adjusted depletion, depreciation and amortization	**$ 329**	$ 372	$ 299	**$ 1,105**	$ 731
$/bbl (1)	**$ 8.96**	$ 9.99	$ 9.03	**$ 9.62**	$ 9.94

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

Adjusted depletion, depreciation and amortization expense per barrel for the Oil Sands Mining and Upgrading segment for the nine months ended September 30, 2018 decreased 3% to $9.62 per bbl from $9.94 per bbl for the nine months ended September 30, 2017. Adjusted depletion, depreciation and amortization expense per barrel for the third quarter of 2018 of $8.96 per bbl was comparable with $9.03 per bbl for the third quarter of 2017, and decreased 10% from $9.99 per bbl for the second quarter of 2018.

The decrease in adjusted depletion, depreciation and amortization expense per barrel for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 was primarily due to the impact of AOSP, which has a lower depletion rate. The decrease in adjusted depletion, depreciation and amortization expense per barrel for the third quarter of 2018 from the second quarter of 2018 was primarily due to the impact of fluctuations in sales volumes from different underlying operations, with a higher proportion of sales during the third quarter subject to a lower depletion rate, as compared with the second quarter of 2018.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Nine Months Ended	
($ millions, except per bbl amounts)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Expense	**$ 16**	$ 15	$ 15	**$ 46**	$ 33
$/bbl (1)	**$ 0.41**	$ 0.41	$ 0.45	**$ 0.40**	$ 0.45

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

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

Asset retirement obligation accretion expense per bbl for the nine months ended September 30, 2018 decreased 11% to $0.40 per bbl from $0.45 per bbl for the nine months ended September 30, 2017 due to higher sales volumes. Asset retirement obligation accretion expense of $0.41 per bbl for the third quarter of 2018 decreased 9% from $0.45 per bbl for the third quarter of 2017 and was comparable with $0.41 per bbl for the second quarter of 2018, primarily due to higher sales volumes in the third quarter of 2018 compared to the third quarter of 2017.

MIDSTREAM

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Revenue	**$ 26**	$ 25	$ 26	**$ 78**	$ 74
Less:					
Production expense	**5**	6	4	**16**	12
Depreciation	**4**	4	2	**11**	6
Equity loss (gain) on investment	**2**	2	(20)	**5**	(32)
Gain on revaluation of properties (1)	**—**	—	(114)	**—**	(114)
Segment earnings before taxes	**$ 15**	$ 13	$ 154	**$ 46**	$ 202

(1) During the third quarter of 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

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

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase, with completion targeted for the first quarter of 2019. 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. To September 30, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $138 million, for a Company total of $577 million. Any additional subordinated debt financing is not expected to be significant.

As per 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, which currently consists of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay the service toll of the syndicated credit facility and bonds over the tolling period of 30 years.

As at September 30, 2018, Redwater Partnership had borrowings of $2,344 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Expense	**$ 77**	$ 76	$ 73	**$ 234**	$ 235
$/BOE (1)	**$ 0.79**	$ 0.79	$ 0.75	**$ 0.80**	$ 0.91

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

Administration expense per BOE for the nine months ended September 30, 2018 decreased 12% to $0.80 per BOE from $0.91 per BOE for the nine months ended September 30, 2017. Administration expense for the third quarter of 2018 of $0.79 per BOE increased 5% from $0.75 per BOE for the third quarter of 2017 and was comparable with $0.79 per BOE for the second quarter of 2018. Administration expense per BOE decreased for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 primarily due to higher sales volumes. The increase in the third quarter of 2018 from the third quarter of 2017 was primarily due to higher overhead recoveries realized in the third quarter of 2017.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Sep 30 2018	Three Months Ended Jun 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
(Recovery) expense	**$ (85)**	$ 175	$ 114	**$ 2**	$ 37

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 $2 million share-based compensation expense for the nine months ended September 30, 2018, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within share-based compensation expense for the nine months ended September 30, 2018 was $8 million related to performance share units granted to certain executive employees (September 30, 2017 – $3 million). For the nine months ended September 30, 2018, the Company recovered $1 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (September 30, 2017 – $2 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Sep 30 2018	Three Months Ended Jun 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Expense, gross	**$ 198**	$ 207	$ 204	**$ 610**	$ 526
Less: capitalized interest	**18**	17	21	**50**	64
Expense, net	**$ 180**	$ 190	$ 183	**$ 560**	$ 462
$/BOE (1)	**$ 1.85**	$ 1.99	$ 1.90	**$ 1.92**	$ 1.79
Average effective interest rate	**4.0%**	3.9%	3.7%	**3.9%**	3.8%

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

Gross interest and other financing expense for the nine months ended September 30, 2018 increased from the nine months ended September 30, 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017. Gross interest and other financing expense for the third quarter of 2018 decreased from the comparable periods primarily due to the impact of lower average debt levels in the third quarter of 2018. Capitalized interest of $50 million for the nine months ended September 30, 2018 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, 2018 increased 7% to $1.92 per BOE from $1.79 per BOE for the nine months ended September 30, 2017. Net interest and other financing expense per BOE for the third quarter of 2018 decreased 3% to $1.85 per BOE from $1.90 per BOE for the third quarter of 2017 and decreased 7% from $1.99 per BOE for the second quarter of 2018. The increase for the nine months ended September 30, 2018 from the nine months ended September 30, 2017 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The decrease for the third quarter of 2018 from the comparable periods was primarily due to higher sales volumes and lower average debt levels in the third quarter of 2018.

The Company's average effective interest rate for the three and nine months ended September 30, 2018 was consistent with the comparable periods.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Crude oil and NGLs financial instruments	**$ —**	$ —	$ (14)	**$ —**	$ (32)
Natural gas financial instruments	**6**	(3)	(4)	**3**	(5)
Foreign currency contracts	**(14)**	(24)	114	**(57)**	108
Realized (gain) loss	**(8)**	(27)	96	**(54)**	71
Crude oil and NGLs financial instruments	**(25)**	—	66	**(25)**	(7)
Natural gas financial instruments	**(14)**	16	1	**2**	(8)
Foreign currency contracts	**18**	(24)	(59)	**(39)**	(23)
Unrealized (gain) loss	**(21)**	(8)	8	**(62)**	(38)
Net (gain) loss	**$ (29)**	$ (35)	$ 104	**$ (116)**	$ 33

During the nine months ended September 30, 2018, net realized risk management gains were primarily related to the settlement of foreign currency contracts. The Company recorded a net unrealized gain of $62 million ($53 million after-tax) on its risk management activities for the nine months ended September 30, 2018, including an unrealized gain of $21 million ($11 million after-tax) for the third quarter of 2018 (June 30, 2018 – unrealized gain of $8 million, $11 million after-tax; September 30, 2017 – unrealized loss of $8 million, $6 million gain after-tax).

Further details related to outstanding derivative financial instruments at September 30, 2018 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Net realized loss (gain)	**$ 14**	$ (7)	$ 37	**$ 123**	$ 49
Net unrealized (gain) loss	**(182)**	178	(404)	**158**	(819)
Net (gain) loss (1)	**$ (168)**	$ 171	$ (367)	**$ 281**	$ (770)

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

The net realized foreign exchange loss for the nine months ended September 30, 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for the nine months ended September 30, 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended September 30, 2018 – unrealized loss of $23 million, June 30, 2018 – unrealized gain of $25 million, September 30, 2017 – unrealized loss of $50 million; nine months ended September 30, 2018 – unrealized gain of $42 million, September 30, 2017 – unrealized loss of $281 million). The US/Canadian dollar exchange rate at September 30, 2018 was US$0.7738 (June 30, 2018 – US$0.7609, September 30, 2017 – US$0.7994).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Sep 30 2018**	Three Months Ended Jun 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended **Sep 30 2018**	Nine Months Ended Sep 30 2017
North America [1]	**$ 169**	$ 247	$ (43)	**$ 566**	$ (52)
North Sea	**12**	7	11	**20**	47
Offshore Africa	**22**	16	14	**43**	28
PRT recovery – North Sea	**(9)**	(16)	(34)	**(29)**	(107)
Other taxes	**3**	3	2	**8**	8
Current income tax expense (recovery)	**197**	257	(50)	**608**	(76)
Deferred corporate income tax expense	**145**	156	141	**428**	279
Deferred PRT expense – North Sea	**1**	7	7	**18**	67
Deferred income tax expense	**146**	163	148	**446**	346
	$ 343	$ 420	$ 98	**$ 1,054**	$ 270
Effective income tax rate on adjusted net earnings from operations [2]	**19%**	23%	32%	**22%**	24%

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

(2) 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, 2018 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, 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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 2018, the Company expects to recognize current income tax expenses ranging from $600 million to $700 million in Canada and $50 million to $80 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Sep 30 2018	Jun 30 2018	Sep 30 2017	Nine Months Ended Sep 30 2018	Sep 30 2017
Exploration and Evaluation					
Net expenditures [2] [3] [4]	**$ 79**	$ 8	$ 66	**$ 143**	$ 133
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**5**	(70)	820	**97**	1,200
Well drilling, completion and equipping	**416**	350	241	**1,087**	789
Production and related facilities	**325**	308	241	**897**	602
Capitalized interest and other [5]	**26**	25	22	**74**	64
Net expenditures	**772**	613	1,324	**2,155**	2,655
Total Exploration and Production	**851**	621	1,390	**2,298**	2,788
Oil Sands Mining and Upgrading					
Project costs [6]	**131**	63	252	**260**	573
Sustaining capital	**173**	152	195	**430**	347
Turnaround costs	**41**	46	75	**100**	86
Acquisitions of Exploration and Evaluation assets [2] [4]	**218**	—	—	**218**	219
Net property acquisitions [2] [4]	**—**	—	—	**—**	11,604
Capitalized interest and other [5]	**(3)**	30	33	**22**	50
Total Oil Sands Mining and Upgrading	**560**	291	555	**1,030**	12,879
Midstream	**2**	5	76	**11**	78
Abandonments [7]	**57**	50	65	**197**	211
Head office	**3**	7	8	**14**	30
Total net capital expenditures	**$ 1,473**	$ 974	$ 2,094	**$ 3,550**	$ 15,986
By segment					
North America [2] [3] [4]	**$ 727**	$ 568	$ 1,327	**$ 2,067**	$ 2,612
North Sea [3]	**35**	3	32	**73**	108
Offshore Africa	**89**	50	31	**158**	68
Oil Sands Mining and Upgrading [4]	**560**	291	555	**1,030**	12,879
Midstream	**2**	5	76	**11**	78
Abandonments [7]	**57**	50	65	**197**	211
Head office	**3**	7	8	**14**	30
Total	**$ 1,473**	$ 974	$ 2,094	**$ 3,550**	$ 15,986

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

(2) Includes business combinations.

(3) Includes proceeds from the acquisition and disposition of properties.

(4) In the second quarter of 2017, total purchase consideration for the acquisition of AOSP of $12,157 million included $26 million of exploration and evaluation assets and $308 million of property, plant and equipment within the North America segment, and $219 million of exploration and evaluation assets and $11,604 million of property, plant and equipment within the Oil Sands Mining and Upgrading segment.

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

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

(7) 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 from Investing Activities

	Three Months Ended			Nine Months Ended	
($ millions)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Cash flows on (from) investing activities	***$ 1,265***	*$ 1,138*	*$ 1,960*	***$ 3,772***	*$ 12,028*
Net change in non-cash working capital [(1)]	***151***	*(207)*	*90*	***(391)***	*(27)*
Investment in other long-term assets	**—**	*(7)*	*(21)*	***(28)***	*(44)*
Share consideration in business acquisitions	**—**	—	—	**—**	*3,818*
Abandonment expenditures	***57***	*50*	*65*	***197***	*211*
Net capital expenditures	***$ 1,473***	*$ 974*	*$ 2,094*	***$ 3,550***	*$ 15,986*

(1) Includes net working capital of $291 million related to the acquisition of AOSP in the second quarter of 2017.

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, 2018 were $3,550 million compared with $15,986 million for the nine months ended September 30, 2017. Net capital expenditures for the third quarter of 2018 were $1,473 million, compared with $2,094 million for the third quarter of 2017 and $974 million for the second quarter of 2018.

Net capital expenditures for the nine months ended September 30, 2018 included:

- $218 million of consideration for the acquisition of the Joslyn oil sands project in the Oil Sands Mining and Upgrading segment (comprising $100 million cash on closing with the remaining balance paid equally over the next five years);
- $22 million of cash consideration for the acquisition of Laricina Energy Ltd. in the North America Exploration and Production segment (net of $24 million of cash acquired); and
- $73 million of cash proceeds for the acquisition of the remaining interest at the Ninian field in the North Sea.

Oil Sands Mining and Upgrading

The Phase 2/3 expansion program will be substantially complete in 2018, with residual scope remaining in 2019 related to Mature Fine Tailings and mine basal water.

Drilling Activity

	Three Months Ended			Nine Months Ended	
(number of net wells)	**Sep 30 2018**	Jun 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Net successful natural gas wells	**6**	4	3	**15**	19
Net successful crude oil wells [(1)]	**178**	81	154	**381**	370
Dry wells	**5**	—	1	**7**	4
Stratigraphic test / service wells	**47**	27	6	**524**	238
Total	**236**	112	164	**927**	631
Success rate (excluding stratigraphic test / service wells)	**97%**	100%	99%	**98%**	99%

(1) Includes bitumen wells.

North America

North America, excluding Oil Sands Mining and Upgrading, accounted for approximately 62% of the total net capital expenditures for the nine months ended September 30, 2018 compared with approximately 17% for the nine months ended September 30, 2017.

During the third quarter of 2018, the Company targeted 6 net natural gas wells, 2 in Northeast British Columbia and 4 in Northwest Alberta. The Company also targeted 181 net crude oil wells. The majority of these wells were concentrated in the Company's Northern Plains region where 113 primary heavy crude oil wells, 41 bitumen (thermal oil) wells and 2 light crude oil wells were drilled. Another 25 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company's strategic and proactive decisions and its ability to utilize capital flexibility based on its large, balanced and diverse asset base has been reflected in the North America drilling program. The Company reallocated capital spending from primary heavy crude oil to light crude oil, with a targeted increase of 29 wells in light oil and a corresponding decrease of 127 wells in heavy oil.

North Sea

During the third quarter of 2018, the Company completed one gross production well and one gross injection well (2.0 on a net basis) in the North Sea (nine months ended September 30, 2018 – four gross production wells and one gross injection well (4.9 on a net basis)), successfully completing the North Sea drilling program.

Offshore Africa

During the third quarter of 2018, the Company completed one gross production well (0.6 on a net basis) at Baobab. The Company is targeting three gross production wells and two gross injection wells for the drilling program at Baobab.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Sep 30 2018**	Jun 30 2018	Dec 31 2017	Sep 30 2017
Working capital (1)	**$ 111**	$ 942	$ 513	$ 205
Long-term debt (2) (3)	**$ 19,733**	$ 21,397	$ 22,458	$ 22,921
Less: cash and cash equivalents	**296**	182	137	312
Long-term debt, net	**$ 19,437**	$ 21,215	$ 22,321	$ 22,609
Share capital	**$ 9,393**	$ 9,405	$ 9,109	$ 8,844
Retained earnings	**24,033**	22,994	22,612	22,552
Accumulated other comprehensive (loss) income	**(33)**	12	(68)	(57)
Shareholders' equity	**$ 33,393**	$ 32,411	$ 31,653	$ 31,339
Debt to book capitalization (3) (4)	**36.8%**	39.6%	41.4%	41.9%
Debt to market capitalization (3) (5)	**27.4%**	26.7%	28.9%	30.8%
After-tax return on average common shareholders' equity (6)	**11.6%**	8.3%	8.0%	8.9%
After-tax return on average capital employed (3) (7)	**8.0%**	5.9%	5.6%	6.2%

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

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

As at September 30, 2018, the Company's capital resources consisted primarily of adjusted funds flow, available bank credit facilities and access to debt capital markets. Adjusted funds flow 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, 2017. 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 adjusted funds flow 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 adjusted funds flow, 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;
- For the nine months ended September 30, 2018, the Company utilized cash flows from operating activities to facilitate net repayment of bank credit facilities and US dollar debt securities of $3,564 million, excluding the impact of foreign exchange on debt balances, including:
    - repayment and cancellation of the $125 million non-revolving credit facility;
    - repayment and cancellation of $1,200 million of the $3,000 million non-revolving term loan facility (third quarter of 2018 – $1,050 million; first quarter of 2018 – $150 million); and
    - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon Oil Corporation for $481 million, resulting in total net repayments of debt of $3,083 million.
- Reviewing the Company's borrowing capacity:
    - During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal 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 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility 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, 2018, the $2,200 million facility was fully drawn.
    - Borrowings under the $750 million non-revolving credit facility 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, 2018, the $750 million facility was fully drawn.
    - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
    - In July 2017, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire 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, 2018, the Company had in place revolving bank credit facilities of $4,975 million which were undrawn and available for use. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. Including cash and cash equivalents and other liquidity, the Company had approximately $5,350 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

As at September 30, 2018, the Company had total US dollar denominated debt with a carrying amount of $13,715 million (US$10,615 million), before transaction costs and original issue discounts. This included $5,185 million (US$4,015 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$2,965 million). The fixed repayment amount of these hedging instruments is $5,010 million, resulting in a notional reduction of the carrying amount of the Company’s US dollar denominated debt by approximately $174 million to $13,541 million as at September 30, 2018.

Net long-term debt was $19,437 million at September 30, 2018, resulting in a debt to book capitalization ratio of 36.8% (December 31, 2017 – 41.4%); 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 adjusted funds flow 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, 2018 are discussed in note 9 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%. At September 30, 2018, 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. At September 30, 2018, 300,000 GJ/d of currently forecasted natural gas volumes were hedged using AECO swaps for October 2018. Additionally, at September 30, 2018, 15,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for October to December 2018 and an additional 8,000 bbl/d were hedged for January to September 2019. Further details related to the Company’s commodity derivative financial instruments outstanding at September 30, 2018 are discussed in note 16 of the Company’s unaudited interim consolidated financial statements.

Share Capital

As at September 30, 2018, there were 1,212,340,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 46,826,000 stock options outstanding. As at October 30, 2018, the Company had 1,205,777,000 common shares outstanding and 46,615,000 stock options outstanding.

On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018 (previous quarterly dividend rate of $0.275 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the nine months ended September 30, 2018, the Company purchased for cancellation 20,012,727 common shares at a weighted average price of $43.66 per common share for a total cost of $874 million. Retained earnings were reduced by $720 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2018, the Company purchased 6,900,000 common shares at a weighted average price of $38.66 per common share for a total cost of $267 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at September 30, 2018:

($ millions)	Remaining 2018	2019	2020	2021	2022	Thereafter
Product transportation and pipeline	$ 169	$ 644	$ 611	$ 585	$ 500	$ 4,250
North West Redwater Partnership debt service toll (1)	$ 24	$ 79	$ 126	$ 157	$ 158	$ 3,015
Offshore equipment operating leases	$ 55	$ 111	$ 69	$ 72	$ 7	$ —
Long-term debt (2)	$ —	$ 1,000	$ 5,826	$ 1,392	$ 1,000	$ 10,640
Interest and other financing expense (3)	$ 181	$ 787	$ 712	$ 579	$ 531	$ 5,544
Office leases	$ 11	$ 43	$ 43	$ 40	$ 31	$ 121
Other	$ 37	$ 48	$ 39	$ 36	$ 35	$ 362

(1) *As per 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, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,318 million of interest payable over the 30 year tolling period.*

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

(3) *Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at September 30, 2018.*

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, refer to the audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2018.

ACCOUNTING POLICIES ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires the recognition of right-of-use assets and lease liabilities on the balance sheet. The Company will elect to apply the exemptions for mineral leases and for certain short-term leases and leases of low-value assets. These leases will not be required to be recognized on the balance sheet.

The new standard is effective January 1, 2019 and is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company plans to adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method. The Company is in the process of reviewing its various arrangements, developing business and accounting processes, and making applicable changes to the Company's internal controls as a result of the new standard.

While the Company has not completed its quantitative analysis of the impacts of IFRS 16, the Company expects material increases in the assets and liabilities reported on the balance sheet. In addition, the Company expects the statement of earnings to be impacted for the amortization of right-of-use assets, interest expense, and lease recoveries from partners, with corresponding decreases in operating, transportation and administrative expenses. Under the new standard, cash outflows for repayment of the principal portion of the lease liability will be classified as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the annual MD&A and the audited consolidated financial statements for the year ended December 31, 2017.

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note		**Sep 30 2018**		Dec 31 2017
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**296**	$	137
Accounts receivable			**1,977**		2,397
Current income taxes receivable			**—**		322
Inventory			**1,118**		894
Prepaids and other			**293**		175
Investments	7		**658**		893
Current portion of other long-term assets	8		**63**		79
			4,405		4,897
Exploration and evaluation assets	4		**2,990**		2,632
Property, plant and equipment	5		**64,705**		65,170
Other long-term assets	8		**1,244**		1,168
		$	**73,344**	$	73,867
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**1,008**	$	775
Accrued liabilities			**2,558**		2,597
Current income taxes payable			**396**		—
Current portion of long-term debt	9		**500**		1,877
Current portion of other long-term liabilities	10		**332**		1,012
			4,794		6,261
Long-term debt	9		**19,233**		20,581
Other long-term liabilities	10		**4,614**		4,397
Deferred income taxes			**11,310**		10,975
			39,951		42,214
SHAREHOLDERS' EQUITY					
Share capital	12		**9,393**		9,109
Retained earnings			**24,033**		22,612
Accumulated other comprehensive loss	13		**(33)**		(68)
			33,393		31,653
		$	**73,344**	$	73,867

Commitments and contingencies (note 17).

Approved by the Board of Directors on October 31, 2018.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Product sales		**$ 6,327**	$ 4,725	**$ 18,451**	$ 12,844
Less: royalties		**(428)**	(259)	**(1,126)**	(705)
Revenue		**5,899**	4,466	**17,325**	12,139
Expenses					
Production		**1,585**	1,597	**4,837**	4,011
Transportation, blending and feedstock		**1,031**	863	**3,325**	2,368
Depletion, depreciation and amortization	5	**1,306**	1,271	**3,833**	3,780
Administration		**77**	73	**234**	235
Share-based compensation	10	**(85)**	114	**2**	37
Asset retirement obligation accretion	10	**47**	44	**140**	119
Interest and other financing expense		**180**	183	**560**	462
Risk management activities	16	**(29)**	104	**(116)**	33
Foreign exchange (gain) loss		**(168)**	(367)	**281**	(770)
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(272)**	(114)	**(411)**	(379)
Loss (gain) from investments	7, 8	**82**	(84)	**219**	(28)
		3,754	3,684	**12,904**	9,868
Earnings before taxes		**2,145**	782	**4,421**	2,271
Current income tax expense (recovery)	11	**197**	(50)	**608**	(76)
Deferred income tax expense	11	**146**	148	**446**	346
Net earnings		**$ 1,802**	$ 684	**$ 3,367**	$ 2,001
Net earnings per common share					
Basic	15	**$ 1.48**	$ 0.56	**$ 2.75**	$ 1.72
Diluted	15	**$ 1.47**	$ 0.56	**$ 2.74**	$ 1.71

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2018	Three Months Ended Sep 30 2017	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Net earnings	**$ 1,802**	$ 684	**$ 3,367**	$ 2,001
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2017 – $3 million) – three months ended; $1 million (2017 – $9 million) – nine months ended	**8**	21	**(7)**	60
Reclassification to net earnings, net of taxes of $2 million (2017 – $1 million) – three months ended; $5 million (2017 – $4 million) – nine months ended	**(9)**	(7)	**(31)**	(29)
	(1)	14	**(38)**	31
Foreign currency translation adjustment				
Translation of net investment	**(44)**	(83)	**73**	(158)
Other comprehensive (loss) income, net of taxes	**(45)**	(69)	**35**	(127)
Comprehensive income	**$ 1,757**	$ 615	**$ 3,402**	$ 1,874

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended Sep 30 2018	Nine Months Ended Sep 30 2017
Share capital	12		
Balance – beginning of period		**$ 9,109**	$ 4,671
Issued for the acquisition of AOSP and other assets (1)	6	**—**	3,818
Issued upon exercise of stock options		**320**	280
Previously recognized liability on stock options exercised for common shares		**118**	75
Purchase of common shares under Normal Course Issuer Bid		**(154)**	—
Balance – end of period		**9,393**	8,844
Retained earnings			
Balance – beginning of period		**22,612**	21,526
Net earnings		**3,367**	2,001
Purchase of common shares under Normal Course Issuer Bid	12	**(720)**	—
Dividends on common shares	12	**(1,226)**	(975)
Balance – end of period		**24,033**	22,552
Accumulated other comprehensive income	13		
Balance – beginning of period		**(68)**	70
Other comprehensive income (loss), net of taxes		**35**	(127)
Balance – end of period		**(33)**	(57)
Shareholders' equity		**$ 33,393**	$ 31,339

(1) In connection with the acquisition of direct and indirect interests in the Athabasca Oil Sands Project ("AOSP") and other assets, the Company issued non-cash share consideration of $3,818 million in the second quarter of 2017. See note 6.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2018**	Three Months Ended Sep 30 2017	Nine Months Ended **Sep 30 2018**	Nine Months Ended Sep 30 2017
Operating activities					
Net earnings		**$ 1,802**	$ 684	**$ 3,367**	$ 2,001
Non-cash items					
Depletion, depreciation and amortization		**1,306**	1,271	**3,833**	3,780
Share-based compensation		**(85)**	114	**2**	37
Asset retirement obligation accretion		**47**	44	**140**	119
Unrealized risk management (gain) loss		**(21)**	8	**(62)**	(38)
Unrealized foreign exchange (gain) loss		**(182)**	(404)	**158**	(819)
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**146**	—
Loss (gain) from investments	7, 8	**89**	(76)	**240**	(7)
Deferred income tax expense		**146**	148	**446**	346
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(272)**	(114)	**(411)**	(379)
Other		**(20)**	(6)	**(5)**	(13)
Abandonment expenditures		**(57)**	(65)	**(197)**	(211)
Net change in non-cash working capital		**889**	918	**1,067**	1,008
		3,642	2,522	**8,724**	5,824
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	9	**(1,468)**	(22)	**(1,847)**	2,612
Issue of medium-term notes, net	9	**—**	—	**—**	1,791
(Repayment) issue of US dollar debt securities, net	9	**—**	—	**(1,236)**	2,733
Issue of common shares on exercise of stock options		**47**	56	**320**	280
Purchase of common shares under Normal Course Issuer Bid		**(433)**	—	**(874)**	—
Dividends on common shares		**(409)**	(334)	**(1,156)**	(917)
		(2,263)	(300)	**(4,793)**	6,499
Investing activities					
Net expenditures on exploration and evaluation assets		**(297)**	(67)	**(361)**	(108)
Net expenditures on property, plant and equipment		**(1,119)**	(1,962)	**(2,992)**	(3,510)
Acquisition of AOSP and other assets, net of cash acquired (1)	6	**—**	—	**—**	(8,630)
Investment in other long-term assets		**—**	(21)	**(28)**	(44)
Net change in non-cash working capital		**151**	90	**(391)**	264
		(1,265)	(1,960)	**(3,772)**	(12,028)
Increase in cash and cash equivalents		**114**	262	**159**	295
Cash and cash equivalents – beginning of period		**182**	50	**137**	17
Cash and cash equivalents – end of period		**$ 296**	$ 312	**$ 296**	$ 312
Interest paid, net		**$ 224**	$ 218	**$ 707**	$ 540
Income taxes received		**$ (118)**	$ (479)	**$ (195)**	$ (804)

(1) The acquisition of AOSP in the second quarter of 2017 includes net working capital of $291 million and excludes non-cash share consideration of $3,818 million. See note 6.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

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

The "Oil Sands Mining and Upgrading" segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's direct and indirect interest in the Athabasca Oil Sands Project ("AOSP").

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

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

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board (“IASB”), applicable to the preparation of interim financial statements, including International Accounting Standard (“IAS”) 34, “Interim Financial Reporting”, following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2017, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company’s annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto for the year ended December 31, 2017.

2. CHANGES IN ACCOUNTING POLICIES

IFRS 15 "Revenue from Contracts with Customers"

In May 2014, the IASB issued IFRS 15 “Revenue from Contracts with Customers” to provide guidance on the recognition of revenue and cash flows arising from an entity’s contracts with customers, and related disclosures. The new standard replaces several existing standards related to recognition of revenue and states that revenue should be recognized as performance obligations related to the goods or services delivered are settled. IFRS 15 also provides revenue accounting guidance for contract modifications and multiple-element contracts and prescribes additional disclosure requirements.

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted this period.

Upon adoption of IFRS 15, the Company applied the practical expedient such that contracts that were completed in the comparative periods have not been restated. Applying this expedient had no impact to the revenue recognized under the previous revenue accounting standard as all performance obligations had been met and the consideration had been determined.

Effective January 1, 2018, the Company’s accounting policy for Revenue is as follows:

Revenue from the sale of crude oil and NGLs and natural gas products is recognized when control of the product passes to the customer and it is probable that the Company will collect the consideration to which it is entitled. Control generally passes to the customer at the point in time when the product is delivered to a location specified in a contract. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statement of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 18.

IFRS 9 "Financial Instruments"

Effective January 1, 2014, the Company adopted the version of IFRS 9 "Financial Instruments" issued November 2013. In July 2014, the IASB issued amendments to IFRS 9 to include accounting guidance to assess and recognize impairment losses on financial assets based on an expected loss model.

The Company retrospectively adopted the amendment to IFRS 9 on January 1, 2018 and elected to apply the limited exemption in IFRS 9 relating to transition for impairment. Accordingly, provisions for impairment have not been restated in the comparative periods. Adoption of the amendment did not have a significant impact on the Company's previous accounting for impairment of financial assets.

Effective January 1, 2018, the Company's accounting policy for impairment of financial assets is as follows:

At each reporting date, on a forward looking basis, the Company assesses the expected credit losses associated with its debt instruments carried at amortized cost. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime losses to be recognized from initial recognition of the receivables. Credit risk is assessed based on the number of days the receivable has been outstanding and an internal credit assessment of the customer. Credit risk for longer-term receivables is assessed based on an internal credit assessment and where available, an external credit rating of the counterparty.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In January 2016, the IASB issued IFRS 16 "Leases", which provides guidance on accounting for leases. The new standard replaces IAS 17 "Leases" and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires the recognition of right-of-use assets and lease liabilities on the balance sheet. The Company will elect to apply the exemptions for mineral leases and for certain short-term leases and leases of low-value assets. These leases will not be required to be recognized on the balance sheet.

The new standard is effective January 1, 2019 and is required to be applied retrospectively, with a policy alternative of restating comparative prior periods or recognizing the cumulative adjustment in opening retained earnings at the date of adoption. The Company plans to adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method. The Company is in the process of reviewing its various arrangements, developing business and accounting processes, and making applicable changes to the Company's internal controls as a result of the new standard.

While the Company has not completed its quantitative analysis of the impacts of IFRS 16, the Company expects material increases in the assets and liabilities reported on the balance sheet. In addition, the Company expects the statement of earnings to be impacted for the amortization of right-of-use assets, interest expense, and lease recoveries from partners, with corresponding decreases in operating, transportation and administrative expenses. Under the new standard, cash outflows for repayment of the principal portion of the lease liability will be classified as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2017	$ 2,282	$ —	$ 91	$ 259	$ 2,632
Additions/Acquisitions	**234**	**—**	**29**	**222**	**485**
Transfers to property, plant and equipment	**(119)**	**—**	**—**	**—**	**(119)**
Disposals/derecognitions and other	**(1)**	**—**	**—**	**(7)**	**(8)**
At September 30, 2018	**$ 2,396**	**$ —**	**$ 120**	**$ 474**	**$ 2,990**

During the nine months ended September 30, 2018, the Company acquired a number of exploration and evaluation properties in the Oil Sands Mining and Upgrading and North America Exploration and Production segments.

In the Oil Sands Mining and Upgrading segment, the Company acquired the Joslyn oil sands project including exploration and evaluation assets of $222 million and associated asset retirement obligations of $4 million. Total consideration of $218 million was comprised of $100 million cash on closing with the remaining balance paid equally over each of the next five years.

In the North America Exploration and Production segment, the Company completed the acquisition of Laricina Energy Ltd., including exploration and evaluation assets of $118 million and property, plant and equipment of $44 million. In addition, the Company also acquired cash of $24 million and deferred income tax assets of $168 million and assumed net working capital liabilities of $18 million, asset retirement obligations of $17 million and notes payable of $48 million. Total purchase consideration was $46 million, resulting in a pre-tax gain of $225 million on the acquisition, representing the excess of the fair value of the net assets acquired compared to total purchase consideration. The Company settled the notes payable immediately following the completion of the acquisition. The transaction was accounted for using the acquisition method of accounting.

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2017	$ 64,816	$ 7,126	$ 4,881	$ 42,084	$ 428	$ 414	$ 119,749
Additions	**2,009**	**293**	**129**	**761**	**11**	**14**	**3,217**
Transfers from E&E assets	**119**	**—**	**—**	**—**	**—**	**—**	**119**
Disposals/derecognitions and other	**(288)**	**—**	**—**	**(127)**	**—**	**—**	**(415)**
Foreign exchange adjustments and other	**—**	**231**	**158**	**—**	**—**	**—**	**389**
At September 30, 2018	**$ 66,656**	**$ 7,650**	**$ 5,168**	**$ 42,718**	**$ 439**	**$ 428**	**$ 123,059**
Accumulated depletion and depreciation							
At December 31, 2017	$ 41,151	$ 5,653	$ 3,719	$ 3,628	$ 124	$ 304	$ 54,579
Expense	**2,337**	**169**	**139**	**1,161**	**11**	**16**	**3,833**
Disposals/derecognitions	**(285)**	**—**	**—**	**(127)**	**—**	**—**	**(412)**
Foreign exchange adjustments and other	**10**	**219**	**133**	**(8)**	**—**	**—**	**354**
At September 30, 2018	**$ 43,213**	**$ 6,041**	**$ 3,991**	**$ 4,654**	**$ 135**	**$ 320**	**$ 58,354**
Net book value							
- at September 30, 2018	**$ 23,443**	**$ 1,609**	**$ 1,177**	**$ 38,064**	**$ 304**	**$ 108**	**$ 64,705**
- at December 31, 2017	$ 23,665	$ 1,473	$ 1,162	$ 38,456	$ 304	$ 110	$ 65,170

Project costs not subject to depletion and depreciation	**Sep 30 2018**	Dec 31 2017
Kirby Thermal Oil Sands – North	**$ 1,300**	$ 944

During the nine months ended September 30, 2018, the Company acquired a number of producing crude oil and natural gas properties in the North America and North Sea Exploration and Production segments. These transactions were accounted for using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to total purchase consideration.

In North America Exploration and Production, excluding the impact of acquisitions disclosed in Note 4, the Company acquired property, plant and equipment for net cash consideration paid of $170 million and assumed associated asset retirement obligations of $13 million. No net deferred income tax liabilities were recognized on these net transactions. The Company recognized a pre-tax gain of $47 million on the transactions.

In connection with the acquisition of the remaining interest in certain operations in the North Sea Exploration and Production segment, the Company acquired $108 million of property, plant and equipment, for net proceeds received of $73 million. The Company also acquired net working capital of $7 million, assumed associated asset retirement obligations of $41 million and recognized net deferred income tax liabilities of $27 million related to temporary differences in the carrying amount of the acquired properties and their tax bases. The Company recognized a pre-tax gain of $120 million on the acquisition and a pre-tax revaluation gain of $19 million relating to its previously held interest.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the nine months ended September 30, 2018, pre-tax interest of $50 million (September 30, 2017 – $64 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (September 30, 2017 – 3.8%).

6. ACQUISITION OF INTERESTS IN THE ATHABASCA OIL SANDS PROJECT AND OTHER ASSETS

On May 31, 2017, the Company completed the acquisition of a direct and indirect 70% interest in AOSP from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), including a 70% interest in the mining and extraction operations north of Fort McMurray, Alberta, 70% of the Scotford Upgrader and Quest Carbon Capture and Storage ("CCS") project, and a 100% working interest in the Peace River thermal in situ operations and Cliffdale heavy oil field, as well as other oil sands leases. The Company also assumed certain pipeline and other commitments. The Company consolidates its direct and indirect interest in the assets, liabilities, revenue and expenses of AOSP and other assets in proportion to the Company's interests.

Total purchase consideration of $12,541 million was comprised of cash payments of $8,217 million, approximately 97.6 million common shares of the Company issued to Shell with a fair value of approximately $3,818 million, and deferred purchase consideration of $506 million (US$375 million) paid to Marathon in March 2018. The fair value of the Company's common shares was determined using the market price of the shares as at the acquisition date.

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The fair value of the assets acquired and liabilities assumed was based on management's best estimate as at the acquisition date. The Company recognized a gain of $230 million, net of transaction costs of $3 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

7. INVESTMENTS

As at September 30, 2018, the Company had the following investments:

	Sep 30 2018	Dec 31 2017
Investment in PrairieSky Royalty Ltd.	**$ 514**	$ 726
Investment in Inter Pipeline Ltd.	**144**	167
	$ 658	$ 893

Investment in PrairieSky Royalty Ltd.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at September 30, 2018, the Company's investment in PrairieSky was classified as a current asset.

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Fair value loss (gain) from PrairieSky	**$ 73**	$ (53)	**$ 212**	$ 1
Dividend income from PrairieSky	**(5)**	(5)	**(13)**	(13)
	$ 68	$ (58)	**$ 199**	$ (12)

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at September 30, 2018, the Company's investment in Inter Pipeline was classified as a current asset.

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Fair value loss (gain) from Inter Pipeline	**$ 14**	$ (3)	**$ 23**	$ 24
Dividend income from Inter Pipeline	**(2)**	(3)	**(8)**	(8)
	$ 12	$ (6)	**$ 15**	$ 16

8. OTHER LONG-TERM ASSETS

		Sep 30 2018		Dec 31 2017
Investment in North West Redwater Partnership	**$**	**287**	$	292
North West Redwater Partnership subordinated debt (1)		**577**		510
Risk management (note 16)		**237**		204
Other		**206**		241
		1,307		1,247
Less: current portion		**63**		79
	$	**1,244**	$	1,168

(1) Includes accrued interest.

Investment in North West Redwater Partnership

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

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase. 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. To September 30, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $138 million, for a Company total of $577 million. Any additional subordinated debt financing is not expected to be significant.

As per 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, which currently consists of interest and fees, with principal repayments beginning in 2020 (see note 17). The Company is unconditionally obligated to pay the service toll of the syndicated credit facility and bonds over the tolling period of 30 years.

As at September 30, 2018, Redwater Partnership had borrowings of $2,344 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

During the three months ended September 30, 2018, the Company recognized an equity loss from Redwater Partnership of $2 million (three months ended September 30, 2017 – gain of $20 million; nine months ended September 30, 2018 – loss of $5 million; nine months ended September 30, 2017 – gain of $32 million).

9. LONG-TERM DEBT

	Sep 30 2018	Dec 31 2017
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 843**	$ 3,544
Medium-term notes	**5,300**	5,300
	6,143	8,844
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2018 - US$2,965 million; December 31, 2017 - US$1,839 million)	**3,829**	2,300
Commercial paper (September 30, 2018 - US$nil; December 31, 2017 - US$500 million)	**—**	625
US dollar debt securities (September 30, 2018 - US$7,650 million; December 31, 2017 - US$8,650 million)	**9,886**	10,828
	13,715	13,753
Long-term debt before transaction costs and original issue discounts, net	**19,858**	22,597
Less: original issue discounts, net (1)	**17**	18
transaction costs (1) (2)	**108**	121
	19,733	22,458
Less: current portion of commercial paper	**—**	625
current portion of other long-term debt (1) (2)	**500**	1,252
	$ 19,233	$ 20,581

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

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

Bank Credit Facilities and Commercial Paper

As at September 30, 2018, the Company had in place revolving bank credit facilities of $4,975 million which were undrawn and available for use. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. Details of these facilities are described below. Including cash and cash equivalents and other liquidity, the Company had approximately $5,350 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,800 million non-revolving term credit facility maturing May 2020;
- a $2,200 million non-revolving term credit facility maturing October 2020;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company’s North Sea operations.

During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal 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 nine months ended September 30, 2018, the Company repaid and cancelled $1,200 million of the $3,000 million non-revolving term credit facility (third quarter of 2018 – $1,050 million; first quarter of 2018 – $150 million) scheduled to mature in May 2020. The required annual amortization of 5% of the original balance is now satisfied. Borrowings under the term loan facility 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, 2018, the $1,800 million facility was fully drawn.

During the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility 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, 2018, the $2,200 million facility was fully drawn.

During the first quarter of 2018, the Company repaid and cancelled the $125 million non-revolving term credit facility scheduled to mature in February 2019. The Company also extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021. Borrowings under the $750 million non-revolving credit facility 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, 2018, the $750 million facility was fully drawn.

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at September 30, 2018 was 2.5% (September 30, 2017 – 2.3%), and on total long-term debt outstanding for the nine months ended September 30, 2018 was 3.9% (September 30, 2017 – 3.8%).

As at September 30, 2018, letters of credit and guarantees aggregating to $417 million were outstanding.

Medium-Term Notes

In July 2017, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

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

In July 2017, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US $3,000 million of debt securities in the United States, which expires in August 2019. 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.

10. OTHER LONG-TERM LIABILITIES

		Sep 30 2018		Dec 31 2017
Asset retirement obligations	$	**4,393**	$	4,327
Share-based compensation		**292**		414
Risk management (note 16)		**32**		103
Deferred purchase consideration (1) (2)		**118**		469
Other		**111**		96
		4,946		5,409
Less: current portion		**332**		1,012
	$	**4,614**	$	4,397

(1) Includes $118 million of deferred purchase consideration at September 30, 2018, payable in annual installments of $25 million over the next five years.

(2) Includes $469 million (US$375 million) of deferred purchase consideration at December 31, 2017, paid to Marathon in March 2018.

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.7% (December 31, 2017 – 4.7%). Reconciliations of the discounted asset retirement obligations were as follows:

		Sep 30 2018		Dec 31 2017
Balance – beginning of period	$	**4,327**	$	3,243
Liabilities incurred		**15**		12
Liabilities acquired, net		**75**		784
Liabilities settled		**(197)**		(274)
Asset retirement obligation accretion		**140**		164
Revision of cost, inflation rates and timing estimates		**—**		(40)
Change in discount rate		**—**		509
Foreign exchange adjustments		**33**		(71)
Balance – end of period		**4,393**		4,327
Less: current portion		**62**		92
	$	**4,331**	$	4,235

Share-Based Compensation

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

	Sep 30 2018	Dec 31 2017
Balance – beginning of period	**$ 414**	$ 426
Share-based compensation expense	**2**	134
Cash payment for stock options surrendered	**(5)**	(6)
Transferred to common shares	**(118)**	(154)
(Recovered from) charged to Oil Sands Mining and Upgrading, net	**(1)**	14
Balance – end of period	**292**	414
Less: current portion	**192**	348
	$ 100	$ 66

Included within share-based compensation expense for the nine months ended September 30, 2018 was $8 million related to performance share units granted to certain executive employees (September 30, 2017 - $3 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Nine Months Ended	
Expense (recovery)	**Sep 30 2018**	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Current corporate income tax – North America	**$ 169**	$ (43)	**$ 566**	$ (52)
Current corporate income tax – North Sea	**12**	11	**20**	47
Current corporate income tax – Offshore Africa	**22**	14	**43**	28
Current PRT (1) – North Sea	**(9)**	(34)	**(29)**	(107)
Other taxes	**3**	2	**8**	8
Current income tax	**197**	(50)	**608**	(76)
Deferred corporate income tax	**145**	141	**428**	279
Deferred PRT (1) – North Sea	**1**	7	**18**	67
Deferred income tax	**146**	148	**446**	346
Income tax	**$ 343**	$ 98	**$ 1,054**	$ 270

(1) Petroleum Revenue Tax.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Nine Months Ended Sep 30, 2018	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,222,769**	**$ 9,109**
Issued upon exercise of stock options	**9,584**	**320**
Previously recognized liability on stock options exercised for common shares	**—**	**118**
Purchase of common shares under Normal Course Issuer Bid	**(20,013)**	**(154)**
Balance – end of period	**1,212,340**	**$ 9,393**

Dividend Policy

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

On February 28, 2018, the Board of Directors declared a quarterly dividend of $0.335 per common share, an increase from the previous quarterly dividend of $0.275 per common share.

Normal Course Issuer Bid

On May 16, 2018, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange, alternative Canadian trading platforms, and the New York Stock Exchange, up to 61,454,856 common shares, over a 12-month period commencing May 23, 2018 and ending May 22, 2019. The Company's Normal Course Issuer Bid announced in March 2017 expired on May 22, 2018.

For the nine months ended September 30, 2018, the Company purchased 20,012,727 common shares at a weighted average price of $43.66 per common share for a total cost of $874 million. Retained earnings were reduced by $720 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to September 30, 2018, the Company purchased 6,900,000 common shares at a weighted average price of $38.66 per common share for a total cost of $267 million.

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2018:

	Nine Months Ended Sep 30, 2018		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**56,036**	**$**	**36.67**
Granted	**3,660**	**$**	**44.64**
Surrendered for cash settlement	**(375)**	**$**	**33.59**
Exercised for common shares	**(9,584)**	**$**	**33.40**
Forfeited	**(2,911)**	**$**	**38.63**
Outstanding – end of period	**46,826**	**$**	**37.87**
Exercisable – end of period	**10,812**	**$**	**35.70**

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

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Sep 30 2018		Sep 30 2017
Derivative financial instruments designated as cash flow hedges	**$**	**9**	$	58
Foreign currency translation adjustment		**(42)**		(115)
	$	**(33)**	$	(57)

14. CAPITAL DISCLOSURES

The Company has defined its capital to mean its long-term debt and consolidated shareholders' equity, as determined at each reporting date.

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At September 30, 2018, the ratio was within the target range at 36.8%.

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

	Sep 30 2018	Dec 31 2017
Long-term debt, net [(1)]	**$ 19,437**	$ 22,321
Total shareholders' equity	**$ 33,393**	$ 31,653
Debt to book capitalization	**36.8%**	41.4%

(1) Includes the current portion of long-term debt, net of cash and cash equivalents.

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%. At September 30, 2018, the Company was in compliance with this covenant.

15. NET EARNINGS PER COMMON SHARE

	Three Months Ended		Nine Months Ended	
	Sep 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Weighted average common shares outstanding – basic (thousands of shares)	**1,218,784**	1,215,616	**1,223,449**	1,160,006
Effect of dilutive stock options (thousands of shares)	**6,083**	6,312	**6,186**	7,520
Weighted average common shares outstanding – diluted (thousands of shares)	**1,224,867**	1,221,928	**1,229,635**	1,167,526
Net earnings	**$ 1,802**	$ 684	**$ 3,367**	$ 2,001
Net earnings per common share – basic	**$ 1.48**	$ 0.56	**$ 2.75**	$ 1.72
– diluted	**$ 1.47**	$ 0.56	**$ 2.74**	$ 1.71

16. FINANCIAL INSTRUMENTS

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

	Sep 30, 2018				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 1,977**	**$ —**	**$ —**	**$ —**	**$ 1,977**
Investments	**—**	**658**	**—**	**—**	**658**
Other long-term assets	**577**	**25**	**212**	**—**	**814**
Accounts payable	**—**	**—**	**—**	**(1,008)**	**(1,008)**
Accrued liabilities	**—**	**—**	**—**	**(2,558)**	**(2,558)**
Other long-term liabilities (1)	**—**	**(4)**	**(28)**	**(118)**	**(150)**
Long-term debt (2)	**—**	**—**	**—**	**(19,733)**	**(19,733)**
	$ 2,554	**$ 679**	**$ 184**	**$ (23,417)**	**$ (20,000)**

	Dec 31, 2017				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,397	$ —	$ —	$ —	$ 2,397
Investments	—	893	—	—	893
Other long-term assets	510	—	204	—	714
Accounts payable	—	—	—	(775)	(775)
Accrued liabilities	—	—	—	(2,597)	(2,597)
Other long-term liabilities (3)	—	(38)	(65)	(469)	(572)
Long-term debt (2)	—	—	—	(22,458)	(22,458)
	$ 2,907	$ 855	$ 139	$ (26,299)	$ (22,398)

(1) Includes $118 million of deferred purchase consideration payable over the next five years.

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

(3) Includes $469 million (US$375 million) of deferred purchase consideration which was paid to Marathon in March 2018.

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

	Sep 30, 2018			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4)
Investments (3)	**$ 658**	**$ 658**	**$ —**	**$ —**
Other long-term assets	**$ 814**	**$ —**	**$ 237**	**$ 577**
Other long-term liabilities	**$ (32)**	**$ —**	**$ (32)**	**$ —**
Fixed rate long-term debt (5) (6)	**$ (15,061)**	**$ (15,787)**	**$ —**	**$ —**

	Dec 31, 2017			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4]
Investments [3]	$ 893	$ 893	$ —	$ —
Other long-term assets	$ 714	$ —	$ 204	$ 510
Other long-term liabilities	$ (103)	$ —	$ (103)	$ —
Fixed rate long-term debt [5] [6]	$ (15,989)	$ (17,259)	$ —	$ —

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

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

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

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

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

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

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

Asset (liability)	**Sep 30 2018**	Dec 31 2017
Derivatives held for trading		
Foreign currency forward contracts	**$ (1)**	$ (38)
Crude oil WCS [1] differential swaps	**25**	—
Natural gas AECO swaps	**(3)**	—
Cash flow hedges		
Foreign currency forward contracts	**(28)**	(71)
Cross currency swaps	**212**	210
	$ 205	$ 101
Included within:		
Current portion of other long-term assets and liabilities	**$ —**	$ (103)
Other long-term assets	**205**	204
	$ 205	$ 101

(1) Western Canadian Select

For the nine months ended September 30, 2018, the Company recognized a gain of $3 million (year ended December 31, 2017 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

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

Risk Management

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

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

Asset (liability)	Sep 30 2018	Dec 31 2017
Balance – beginning of period	**$ 101**	$ 489
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**62**	(37)
Foreign exchange	**86**	(375)
Other comprehensive (loss) income	**(44)**	24
Balance – end of period	**205**	101
Less: current portion	**—**	(103)
	$ 205	$ 204

Net (gain) loss from risk management activities were as follows:

	Three Months Ended		Nine Months Ended	
	Sep 30 2018	Sep 30 2017	**Sep 30 2018**	Sep 30 2017
Net realized risk management (gain) loss	**$ (8)**	$ 96	**$ (54)**	$ 71
Net unrealized risk management (gain) loss	**(21)**	8	**(62)**	(38)
	$ (29)	$ 104	**$ (116)**	$ 33

Financial Risk Factors

a) Market risk

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

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

At September 30, 2018, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	Volume	Weighted average price	Index
Crude Oil				
WCS differential swaps	Oct 2018 - Dec 2018	15,000 bbl/d	US$24.75	WCS
	Jan 2019 - Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas				
AECO swaps	Oct 2018	100,000 GJ/d	$1.01	AECO
	Oct 2018	200,000 GJ/d	$1.08	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At September 30, 2018, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At September 30, 2018, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Oct 2018	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2018	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at September 30, 2018 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2018, the Company had US$3,322 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$2,965 million designated as cash flow hedges.

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At September 30, 2018, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At September 30, 2018, the Company had net risk management assets of $227 million with specific counterparties related to derivative financial instruments (December 31, 2017 – $187 million).

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

c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

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

The maturity dates for financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	1,008	$	—	$	—	$	—
Accrued liabilities	$	2,558	$	—	$	—	$	—
Other long-term liabilities	$	57	$	24	$	69	$	—
Long-term debt (1) (2)	$	500	$	4,170	$	5,840	$	9,348

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

(2) In addition to the financial liabilities disclosed above, estimated interest and other financing payments are as follows: less than one year, $795 million; one to less than two years, $755 million; two to less than five years, $1,623 million; and thereafter, $5,161 million. Interest payments were estimated based upon applicable interest and foreign exchange rates at September 30, 2018.

17. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

		Remaining 2018		2019		2020		2021		2022		Thereafter
Product transportation and pipeline	$	169	$	644	$	611	$	585	$	500	$	4,250
North West Redwater Partnership service toll (1)	$	24	$	79	$	126	$	157	$	158	$	3,015
Offshore equipment operating leases	$	55	$	111	$	69	$	72	$	7	$	—
Office leases	$	11	$	43	$	43	$	40	$	31	$	121
Other	$	37	$	48	$	39	$	36	$	35	$	362

(1) As per 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, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the service toll is $1,318 million of interest payable over the 30 year tolling period. See note 8.

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.

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.

18. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**2,162**	1,779	**6,331**	5,390	**201**	152	**535**	484	**230**	180	**424**	409	**2,593**	2,111	**7,290**	6,283
Natural gas	**265**	317	**834**	1,179	**45**	33	**112**	85	**18**	16	**53**	39	**328**	366	**999**	1,303
Total segmented product sales	**2,427**	2,096	**7,165**	6,569	**246**	185	**647**	569	**248**	196	**477**	448	**2,921**	2,477	**8,289**	7,586
Less: royalties	**(247)**	(201)	**(685)**	(581)	**—**	—	**(1)**	(1)	**(22)**	(12)	**(42)**	(25)	**(269)**	(213)	**(728)**	(607)
Segmented revenue	**2,180**	1,895	**6,480**	5,988	**246**	185	**646**	568	**226**	184	**435**	423	**2,652**	2,264	**7,561**	6,979
Segmented expenses																
Production	**576**	569	**1,816**	1,730	**96**	95	**271**	281	**52**	82	**121**	180	**724**	746	**2,208**	2,191
Transportation, blending and feedstock	**613**	472	**2,046**	1,626	**6**	8	**18**	26	**—**	—	**1**	1	**619**	480	**2,065**	1,653
Depletion, depreciation and amortization	**795**	821	**2,353**	2,393	**53**	71	**169**	472	**69**	53	**139**	153	**917**	945	**2,661**	3,018
Asset retirement obligation accretion	**22**	20	**66**	59	**7**	7	**21**	21	**2**	2	**7**	6	**31**	29	**94**	86
Risk management activities (commodity derivatives)	**(32)**	49	**(19)**	(52)	**—**	—	**—**	—	**—**	—	**—**	—	**(32)**	49	**(19)**	(52)
Gain on acquisition, disposition and revaluation of properties	**(272)**	—	**(272)**	(35)	**—**	—	**(139)**	—	**—**	—	**—**	—	**(272)**	—	**(411)**	(35)
Equity loss (gain) from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**1,702**	1,931	**5,990**	5,721	**162**	181	**340**	800	**123**	137	**268**	340	**1,987**	2,249	**6,598**	6,861
Segmented earnings (loss) before the following	**478**	(36)	**490**	267	**84**	4	**306**	(232)	**103**	47	**167**	83	**665**	15	**963**	118
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings before taxes																
Current income tax expense (recovery)																
Deferred income tax expense																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30		Three Months Ended Sep 30		Nine Months Ended Sep 30	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**3,219**	2,067	**9,683**	4,749	**26**	26	**78**	74	**129**	116	**290**	318	**5,967**	4,320	**17,341**	11,424
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**32**	39	**111**	117	**360**	405	**1,110**	1,420
Total segmented product sales	**3,219**	2,067	**9,683**	4,749	**26**	26	**78**	74	**161**	155	**401**	435	**6,327**	4,725	**18,451**	12,844
Less: royalties	**(159)**	(46)	**(398)**	(98)	**—**	—	**—**	—	**—**	—	**—**	—	**(428)**	(259)	**(1,126)**	(705)
Segmented revenue	**3,060**	2,021	**9,285**	4,651	**26**	26	**78**	74	**161**	155	**401**	435	**5,899**	4,466	**17,325**	12,139
Segmented expenses																
Production	**842**	829	**2,570**	1,754	**5**	4	**16**	12	**14**	18	**43**	54	**1,585**	1,597	**4,837**	4,011
Transportation, blending and feedstock	**265**	246	**913**	340	**—**	—	**—**	—	**147**	137	**347**	375	**1,031**	863	**3,325**	2,368
Depletion, depreciation and amortization	**385**	324	**1,161**	756	**4**	2	**11**	6	**—**	—	**—**	—	**1,306**	1,271	**3,833**	3,780
Asset retirement obligation accretion	**16**	15	**46**	33	**—**	—	**—**	—	**—**	—	**—**	—	**47**	44	**140**	119
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**(32)**	49	**(19)**	(52)
Gain on acquisition, disposition and revaluation of properties	**—**	—	**—**	(230)	**—**	(114)	**—**	(114)	**—**	—	**—**	—	**(272)**	(114)	**(411)**	(379)
Equity loss (gain) from investments	**—**	—	**—**	—	**2**	(20)	**5**	(32)	**—**	—	**—**	—	**2**	(20)	**5**	(32)
Total segmented expenses	**1,508**	1,414	**4,690**	2,653	**11**	(128)	**32**	(128)	**161**	155	**390**	429	**3,667**	3,690	**11,710**	9,815
Segmented earnings (loss) before the following	**1,552**	607	**4,595**	1,998	**15**	154	**46**	202	**—**	—	**11**	6	**2,232**	776	**5,615**	2,324
Non–segmented expenses																
Administration													**77**	73	**234**	235
Share-based compensation													**(85)**	114	**2**	37
Interest and other financing expense													**180**	183	**560**	462
Risk management activities (other)													**3**	55	**(97)**	85
Foreign exchange (gain) loss													**(168)**	(367)	**281**	(770)
Loss (gain) from investments													**80**	(64)	**214**	4
Total non–segmented expenses													**87**	(6)	**1,194**	53
Earnings before taxes													**2,145**	782	**4,421**	2,271
Current income tax expense (recovery)													**197**	(50)	**608**	(76)
Deferred income tax expense													**146**	148	**446**	346
Net earnings													**1,802**	684	**3,367**	2,001

Capital Expenditures [1]

	Nine Months Ended					
	Sep 30, 2018			Sep 30, 2017		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net [3] expenditures	Non-cash and fair value changes [2][3]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [4]	**$ 114**	**$ —**	**$ 114**	$ 149	$ (162)	$ (13)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**29**	**—**	**29**	10	—	10
Oil Sands Mining and Upgrading	**218**	**(3)**	**215**	142	117	259
	$ 361	**$ (3)**	**$ 358**	$ 301	$ (45)	$ 256
Property, plant and equipment						
Exploration and Production						
North America	**$ 1,953**	**$ (113)**	**$ 1,840**	$ 2,382	$ 254	$ 2,636
North Sea	**73**	**220**	**293**	108	20	128
Offshore Africa	**129**	**—**	**129**	58	4	62
	2,155	**107**	**2,262**	2,548	278	2,826
Oil Sands Mining and Upgrading [5]	**812**	**(178)**	**634**	9,035	5,764	14,799
Midstream [6]	**11**	**—**	**11**	78	114	192
Head office	**14**	**—**	**14**	30	—	30
	$ 2,992	**$ (71)**	**$ 2,921**	$ 11,691	$ 6,156	$ 17,847

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

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

(3) Net expenditures on exploration and evaluation assets and property, plant and equipment for the nine months ended September 30, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.

(4) The above noted figures for 2017 do not include the impact of a pre-tax cash gain of $35 million on the disposition of certain exploration and evaluation assets.

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

(6) Included in 2017 is the impact of a pre-tax non-cash revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system.

Segmented Assets

	Sep 30 2018	Dec 31 2017
Exploration and Production		
North America	**$ 28,262**	$ 28,705
North Sea	**1,826**	1,854
Offshore Africa	**1,440**	1,331
Other	**59**	29
Oil Sands Mining and Upgrading	**40,208**	40,559
Midstream	**1,441**	1,279
Head office	**108**	110
	$ 73,344	$ 73,867

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 2017. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended September 30, 2018:	
Interest coverage (times)	
Net earnings (1)	7.3x
Adjusted funds flow (2)	14.4x

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

(2) Adjusted funds flow plus current income taxes and interest expense excluding current PRT expense and other taxes; divided by the sum of interest expense and capitalized interest.

Corporate Information

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Ambassador Gordon D. Giffin

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Vice-President and Managing Director, International

Barry Duncan
Vice-President, Finance, International

Stock Listing
Toronto Stock Exchange
Trading Symbol - CNQ
New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

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