THIRD QUARTER REPORT

NINE MONTHS ENDED SEPTEMBER 30, 2019 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2019 THIRD QUARTER RESULTS

Commenting on the Company's third quarter 2019 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "Canadian Natural's third quarter results are an excellent example of how the Company's effective and efficient operations can drive value creation for our shareholders as a result of execution excellence and economies of scale. We achieved record quarterly adjusted funds flow of approximately $2.9 billion as operating costs were below forecast and production was at the top end of quarterly corporate guidance, resulting in 12 month production per share growth of 14% from Q3/18 levels. Free cash flow of approximately $1.9 billion was significant following our disciplined capital expenditures in the quarter. Our free cash flow was used to strengthen our balance sheet and returned to our shareholders, through dividends and share purchases as we balance according to our defined free cash flow allocation policy."

Canadian Natural's President, Tim McKay, added, "The third quarter of 2019 was an excellent operational quarter for the Company. Our continued focus on cost control and effective and efficient operations was evident as operating costs were reduced across most of our assets, resulting in higher netbacks and margin growth. Corporate operating costs per BOE were reduced by approximately 11%, including at our Pelican Lake asset where strong and sustainable operating costs of $6.10/bbl were achieved, a reduction of 5% year over year. Also on a year over year basis our Thermal in situ assets operating costs improved by approximately 14% to $9.77/bbl and our Oil Sands Mining and Upgrading assets delivered an approximate 12% reduction in operating costs to $20.05/bbl of Synthetic Crude Oil ("SCO"), comparable to the record low of $19.97/bbl of SCO in Q4/18.

The Company delivered strong performance in the third quarter, a reflection of our robust assets, effective and efficient operations and our operational flexibility, as we effectively executed our curtailment optimization strategy, delivering production at the top end of quarterly guidance. Oil Sands Mining and Upgrading achieved a record production month in the quarter, producing approximately 462,000 bbl/d of SCO in August 2019. In September and October, as a part of our curtailment optimization strategy, we utilized available capacity from our flexible thermal in situ assets to coincide with the Horizon turnaround ensuring we maximized production within our curtailment allotment. This flexibility demonstrates the value of having a large, balanced and diverse asset base. As a result of top tier execution, the planned turnaround at Horizon was successfully completed on schedule with overall costs under budget."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, continued, "Canadian Natural's robust business model was on display in the third quarter as financial results were strong with net earnings of over $1.0 billion and adjusted net earnings of approximately $1.2 billion.

The Company's long life low decline asset base delivered quarterly record adjusted funds flow of approximately $2.9 billion and as a result free cash flow generation was significant at approximately $1.5 billion after capital expenditures and dividends. Our financial position strengthened in Q3/19 as we reduced gross debt by over $1.0 billion from Q2/19 levels. This included the permanent repayment and cancellation of term debt by $800 million in the quarter, followed by an additional $500 million repayment and cancellation subsequent to quarter end. Based on corporate guidance and current strip pricing we target to exit 2019 with debt to adjusted EBITDA at or below 1.9x, debt to cash flow at or below 2.2x and debt to book capital at or below 38%, all levels that are stronger than those exiting December 31, 2018, notwithstanding the completion of the Devon Canada asset acquisition."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Sep 30 2019	Three Months Ended Jun 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Net earnings	**$ 1,027**	$ 2,831	$ 1,802	**$ 4,819**	$ 3,367
Per common share – basic	**$ 0.87**	$ 2.37	$ 1.48	**$ 4.04**	$ 2.75
– diluted	**$ 0.87**	$ 2.36	$ 1.47	**$ 4.03**	$ 2.74
Adjusted net earnings from operations (1)	**$ 1,229**	$ 1,042	$ 1,354	**$ 3,109**	$ 3,518
Per common share – basic	**$ 1.04**	$ 0.87	$ 1.11	**$ 2.61**	$ 2.88
– diluted	**$ 1.04**	$ 0.87	$ 1.11	**$ 2.60**	$ 2.86
Cash flows from operating activities	**$ 2,518**	$ 2,861	$ 3,642	**$ 6,375**	$ 8,724
Adjusted funds flow (2)	**$ 2,881**	$ 2,652	$ 2,830	**$ 7,773**	$ 7,859
Per common share – basic	**$ 2.43**	$ 2.22	$ 2.32	**$ 6.51**	$ 6.42
– diluted	**$ 2.43**	$ 2.22	$ 2.31	**$ 6.50**	$ 6.39
Cash flows used in investing activities	**$ 908**	$ 4,464	$ 1,265	**$ 6,401**	$ 3,772
Net capital expenditures, excluding Devon Canada asset acquisition costs (3)	**$ 963**	$ 908	$ 1,473	**$ 2,848**	$ 3,550
Total net capital expenditures, including Devon Canada asset acquisition costs (3)	**$ 963**	$ 4,125	$ 1,473	**$ 6,065**	$ 3,550
Daily production, before royalties					
Natural gas (MMcf/d)	**1,469**	1,532	1,553	**1,504**	1,568
Crude oil and NGLs (bbl/d)	**931,546**	770,409	801,742	**829,031**	816,539
Equivalent production (BOE/d) (4)	**1,176,361**	1,025,800	1,060,629	**1,079,641**	1,077,953

(1) Adjusted net earnings from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the "Advisory" section of this press release.

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key to evaluate its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The derivation of this measure is discussed in the "Advisory" section of this press release.

(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 "Advisory" section of this press release.

(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 $1,027 million were realized in Q3/19, while adjusted net earnings of $1,229 million were achieved in Q3/19, a $187 million increase from Q2/19 levels.
- Cash flows from operating activities were $2,518 million in Q3/19, a decrease of $343 million compared to Q2/19 levels.
- Canadian Natural generated record quarterly adjusted funds flow of $2,881 million in Q3/19, an increase of 9% or $229 million over Q2/19 levels. The increase over Q2/19 was primarily due to higher production volumes from the Company's Thermal in situ, Oil Sands Mining and Upgrading, Primary Heavy and Pelican Lake crude oil segments and strong operating costs which were partially offset by lower light crude oil and heavy crude oil pricing in the quarter.
- Cash flows used in investing activities were $908 million in Q3/19.

- Canadian Natural delivered strong quarterly free cash flow of $1,471 million after net capital expenditures of $963 million, and dividend requirements of $447 million in Q3/19, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
  - Balance sheet strength remains a focus and free cash flow was used to reduce debt levels in Q3/19 as the Company balances its free cash flow according to the defined free cash flow allocation policy. As a result gross long-term debt was reduced in Q3/19 by $1,018 million from Q2/19 levels.
    - The Company utilized adjusted funds flow to repay and cancel $800 million of its $1,800 million non-revolving term loan facility; $1,000 million remained outstanding and fully drawn at quarter end.
      - Subsequent to quarter end the Company repaid and canceled an additional $500 million of the remaining $1,000 million non-revolving term loan; $500 million remains outstanding and fully drawn as at November 6, 2019.
  - Canadian Natural is committed to returns to shareholders, returning a total of $616 million to shareholders in Q3/19, $447 million by way of dividends and $169 million by way of share purchases. In the first nine months of 2019, the Company has returned a total of $2,100 million to shareholders, $1,299 million by way of dividends and $801 million by way of share purchases.
    - Share purchases for cancellation in the quarter totaled 5,050,000 common shares at a weighted average share price of $33.45.
    - Subsequent to quarter end, up to and including November 6, 2019, the Company executed on additional share purchases for cancellation of 1,350,000 common shares at a weighted average share price of $33.70.
    - Returns to shareholders have been significant as Canadian Natural has returned approximately $5.4 billion by way of dividends and share purchases between January 1, 2018 and November 6, 2019.
    - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on January 1, 2020.
- The Company continues to manage within its curtailment optimization strategy which in addition to strong operational performance, contributed to production levels that are at the top end of guidance guidance. The Company continues to execute operational flexibility through its curtailment optimization strategy as follows:
  - Mitigating production impacts, from lower production at Horizon due to planned maintenance activities, by increasing Athabasca Oil Sands Project ("AOSP"), conventional crude oil and thermal in situ crude oil production. As a result, strong production was realized at the Company's North America Exploration and Production ("E&P") and thermal in situ oil sands assets in Q3/19.
  - Modified timing of the Company's planned turnaround activities to achieve its monthly curtailment allowable.
  - Maximizing value through production optimization of higher netback assets and reducing operating costs.
- The Company achieved quarterly production volumes of 1,176,361 BOE/d in Q3/19, increases of 15% and 11% over Q2/19 and Q3/18 levels respectively, reflecting production additions from the Devon Canada asset acquisition that closed on June 27, 2019, together with strong operational performance at both Horizon and AOSP.
  - As a result of accretive acquisitions, effective and efficient operations and execution on the Company's free cash flow allocation policy, annual production per share growth was significant at 14% when compared to Q3/18 levels.
  - The Company achieved record quarterly liquids production volumes of 931,546 bbl/d in Q3/19, increases of 21% and 16% over Q2/19 and Q3/18 levels respectively and at the top end of previously issued guidance.
- At the Company's world class Oil Sands Mining and Upgrading assets, production volumes were strong, at the top end of production guidance, averaging 432,203 bbl/d of Synthetic Crude Oil ("SCO") in Q3/19, increases of 15% and 10% over Q2/19 and Q3/18 levels respectively. The increases were primarily as a result of strong operational performance as well as modified timing of the Horizon turnaround schedule as a part of the Company's curtailment optimization strategy.
  - Effective and efficient operations and high reliability resulted in strong quarterly operating costs of $20.05/bbl (US$15.18/bbl) of SCO in Q3/19, comparable to record low operating costs of $19.97/bbl (US$15.12/bbl) of SCO achieved in Q4/18, impressive results given the planned turnaround activities in the quarter. Q3/19 operating costs represent decreases of 17% and 12% from Q2/19 and Q3/18 levels respectively.
  - At the Albian mines, top tier operations combined with enhancing and optimization of equipment resulted in record gross bitumen production averaging approximately 318,000 bbl/d in September and October, forming a part of

the Company's curtailment optimization strategy during the Horizon turnaround. These results are significant as the two month average throughput was approximately 38,000 bbl/d or 14% above capability announced at the time of the acquisition. The Company continues to maximize value from acquired assets through lower operating costs and enhancing and optimizing production.

  - At Horizon, subsequent to quarter end the Company successfully completed a planned turnaround on schedule and under budget demonstrating strong execution by the Company's teams.
  - As part of the Company's proactive inspection at Horizon, the team identified a need to repair piping on one of the hydrogen manufacturing units during post turnaround start-up. As a result, Horizon is currently running at restricted rates of approximately 155,000 bbl/d and is targeted to return to full rates by early December 2019. The Company's targets to remain within its previous annual production guidance range.

- Thermal in situ oil sands production volumes exceeded the top end of quarterly production guidance as the Company demonstrated the flexibility and available capacity of its thermal in situ assets by utilizing allowable volumes during the Horizon turnaround of approximately 28,000 bbl/d in September from Jackfish, Kirby North and pad additions at Primrose. Production in Q3/19 averaged 206,395 bbl/d, an 88% increase over Q2/19 levels, primarily reflecting a full quarter of production from the Devon Canada asset acquisition and the successful execution on the Company's curtailment optimization strategy.
  - Thermal in situ operating costs were strong in Q3/19 at $9.77/bbl, reductions of 17% and 14% from Q2/19 and Q3/18 levels respectively, primarily as a result of synergies captured to date from the Devon Canada acquisition and lower energy costs.
  - At Kirby North, top tier execution and productivity have resulted in production averaging approximately 6,600 bbl/d in September 2019, exceeding production forecasts. Strong performance results are primarily due to improved well design, high plant reliability and other operational improvements. Production volumes will be managed as part of the Company's curtailment optimization strategy as the Company ramps up towards Kirby North's overall capacity of 40,000 bbl/d targeted in early 2021.
  - At Primrose, as a result of strong execution the Company's high return pad additions came on ahead of schedule and on budget. Production from the pad additions were strong, beginning on September 16, 2019, utilizing available oil processing and steam capacity with managed production averaging approximately 13,600 bbl/d in September, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy.
  - At Jackfish, pad additions that have been successfully drilled and not completed to date due to curtailments in Alberta have a production capability of 21,000 bbl/d. These pads require minimal capital of approximately $8 million to complete tie in activities that are targeted for Q4/19. Production from these pads is targeted to offset conventional production declines with long life low decline thermal in situ production, as the Company manages within its curtailment optimization strategy and targets to reach peak production in 2022.
- The Company continues to execute its plan to achieve its initially identified targeted annual cost savings of at least $135 million for both primary heavy and thermal in situ crude oil assets acquired from Devon Canada. As previously announced, approximately $25 million of these initially identified synergies are being realized more than one year ahead of the initial plan.
  - Additionally, in the short time since closing Canadian Natural has identified incremental targeted annual savings of approximately $10 million and approximately $50 million of one time capital cost savings on its thermal in situ and primary heavy crude oil assets driving incremental value for the Company's shareholders.
- Canadian Natural's continued focus on delivering effective and efficient operations and cost control was demonstrated as the Company's E&P Q3/19 operating costs were $11.11/BOE, 5% and 7% reductions from Q2/19 and Q3/18 levels respectively.
- Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 244,267 bbl/d in Q3/19, a 4% increase over Q2/19 and in line with Q3/18 levels. The increase over Q2/19 was primarily due to a full quarter of production from primary heavy crude oil assets acquired from Devon Canada.
  - At Pelican Lake the Company continues to demonstrate effective and efficient operations as operating costs have averaged approximately $6.50/bbl over the last 4 years. These sustainable and consistent results continued in Q3/19 where operating costs of $6.10/bbl were achieved, representing decreases of 9% and 5% from Q2/19 and Q3/18 levels respectively. The reductions were mainly as a result of the Company's focus on cost control and savings achieved from facility consolidation completed in Q2/19.

- International E&P production volumes were strong in Q3/19, exceeding quarterly production guidance, averaging 48,681 bbl/d, a decrease of 5% from Q2/19 and an increase of 2% over Q3/18 levels. The decrease from Q2/19 is primarily due to planned turnaround activities in the North Sea and natural field declines partially offset by strong performance from new wells. The increase from Q3/18 was primarily as a result of strong volumes from new wells drilled at Baobab and in the North Sea in late 2018 and 2019.
- Corporate natural gas production averaged 1,469 MMcf/d in Q3/19, exceeding the top end of quarterly guidance as a result of phasing of turnaround activities. As compared to Q2/19 and Q3/18 levels, natural gas production decreased by 4% and 5% respectively, primarily due to natural field declines and reduced capital investment.
  - Strong operating costs of $1.12/Mcf were achieved in Q3/19, decreases of 9% and 16% from Q2/19 and Q3/18 levels respectively. The operating cost decreases were primarily due to the Company's continued focus on cost control and the impact of increased processed volumes at strategically owned and operated facilities.
- Incremental egress of approximately 225,000 bbl/d to move incremental crude oil production out of the Western Canadian Sedimentary Basin ("WCSB") is targeted to be added over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Mainline enhancements are targeted to add approximately 85,000 bbl/d of capacity targeted to be available in December 2019.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in Q1/20.
  - The North West Redwater Refinery ("NWR") is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available early in 2020.
  - Crude by rail volumes continue to be strong at approximately 310,000 bbl/d for the month of August 2019.

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 crude oil, medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal in situ crude oil, bitumen and SCO (herein collectively referred to as "crude oil"), natural gas and NGLs. This balance provides optionality for capital investments, maximizing 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 long life low decline, low reserves replacement cost, and effective and efficient operations results in 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 the Company's 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 major components of the Company's operating costs 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			
	2019		2018	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**80**	**74**	402	381
Natural gas	**21**	**15**	19	15
Dry	**3**	**3**	7	7
Subtotal	**104**	**92**	428	403
Stratigraphic test / service wells	**411**	**358**	617	524
Total	**515**	**450**	1,045	927
Success rate (excluding stratigraphic test / service wells)		**97%**		98%

- The Company's total crude oil and natural gas drilling program of 92 net wells for the nine months ended September 30, 2019, excluding strat/service wells, represents a decrease of 311 net wells from the same period in 2018. The Company's drilling levels primarily reflect the impacts of reduced capital allocation as a result of Alberta curtailments and execution of the Company's curtailment optimization strategy.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs production (bbl/d)	**244,267**	235,066	247,314	**234,944**	243,857
Net wells targeting crude oil	**33**	9	140	**70**	299
Net successful wells drilled	**33**	7	135	**68**	292
Success rate	**100%**	78%	96%	**97%**	98%

- Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 244,267 bbl/d in Q3/19, a 4% increase over Q2/19 and in line with Q3/18 levels. The increase was primarily due to a full quarter of production from the acquired primary heavy crude oil assets from Devon Canada.

- Canadian Natural's primary heavy crude oil production averaged 88,008 bbl/d in Q3/19, a 13% increase over Q2/19 levels primarily due to additional volumes from the Devon Canada asset acquisition. Primary heavy crude oil production decreased by 4% from Q3/18 levels primarily due to curtailments and natural field declines, partially offset by additional volumes from the Devon Canada asset acquisition.
    - Operating costs of $17.08/bbl were achieved in the Company's primary heavy crude oil operations in the quarter, a 3% decrease from Q2/19 levels.
    - As a result of curtailments in Alberta the Company drilled 7 net primary heavy crude oil wells in Saskatchewan in Q3/19, targeting strategic opportunities for future development, as these wells are not impacted by curtailment. Canadian Natural is leveraging the Company's multilateral horizontal technology expertise on these wells where early results of approximately 140 bbl/d per well are in line with expectations.
- Pelican Lake quarterly production averaged 60,146 bbl/d in Q3/19, an increase of 9% from Q2/19 levels, reflecting normal production levels after the temporary shut-in of crude oil production in Q2/19 due to wildfires in northern Alberta.
    - At Pelican Lake the Company continues to demonstrate effective and efficient operations as operating costs have averaged approximately $6.50/bbl over the last 4 years. These sustainable and consistent results continued in Q3/19 where operating costs of $6.10/bbl were achieved, representing decreases of 9% and 5% from Q2/19 and Q3/18 levels respectively. The reductions were mainly as a result of the Company's focus on cost control and savings achieved from facility consolidation completed in Q2/19.
- North American light crude oil and NGL production averaged 96,113 bbl/d in Q3/19, a 6% decrease from Q2/19 levels primarily as a result of curtailments in Alberta and natural field declines. Production increased 3% from Q3/18 levels reflecting the Company's strategic decision to reallocate capital to light crude oil and liquids rich areas, along with strong results from the 2018 and 2019 drilling programs at Wembley, Karr, and Southeast Saskatchewan combined with the execution of the Company's curtailment optimization strategy.
    - In Q3/19 operating costs were $14.96/bbl in the Company's North America light crude oil and NGL areas, an increase of 2% over Q2/19 and a decrease of 4% from Q3/18 levels. The changes from Q2/19 and Q3/18 levels primarily reflect changes in production volumes noted above and the Company's focus on cost control.
    - Within the greater Wembley area, results from the 27 net wells drilled in 2018 and 3 net wells drilled in 2019 continue to be strong with production averaging approximately 10,400 bbl/d liquids and 68 MMcf/d, exceeding expectations by approximately 40%.
    - In Southeast Saskatchewan, the Company drilled 8 gross (6.6 net) light crude oil wells in Q3/19, with 3 gross (3.0 net) wells previously drilled in Q2/19 as a part of the program. These high return wells came on stream in Q3/19 with strong initial rates from the total program averaging approximately 100 bbl/d per well, exceeding expectations. The Company strategically reallocated conventional capital from Alberta to Saskatchewan as production from these wells is not impacted by the Government of Alberta mandated production curtailment.

▪ The Company’s annual 2019 North America E&P crude oil and NGL production guidance remains unchanged and is targeted to range between 231,000 bbl/d - 251,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Bitumen production (bbl/d)	**206,395**	109,599	112,542	**137,124**	109,769
Net wells targeting bitumen	**—**	—	41	**—**	84
Net successful wells drilled	**—**	—	41	**—**	84
Success rate	**—**	—	100%	**—**	100%

▪ Thermal in situ oil sands production volumes exceeded the top end of quarterly production guidance as the Company demonstrated the flexibility and available capacity of its thermal in situ assets by utilizing allowable volumes during the Horizon turnaround of approximately 28,000 bbl/d in September from Jackfish, Kirby North and pad additions at Primrose. Production in Q3/19 averaged 206,395 bbl/d, an 88% increase over Q2/19 levels, primarily reflecting a full quarter of production from the Devon Canada asset acquisition and the successful execution on the Company's curtailment optimization strategy.

- Thermal in situ operating costs were strong in Q3/19 at $9.77/bbl, reductions of 17% and 14% from Q2/19 and Q3/18 levels respectively, primarily as a result of synergies captured to date from the Devon Canada acquisition and lower energy costs.
- At Primrose, Q3/19 production volumes averaged 73,652 bbl/d, an increase of 2% over Q2/19 levels, primarily due to execution on the Company's curtailment optimization strategy. Including energy costs, operating costs were strong at $9.91/bbl in Q2/19, decreases of 20% and 16% from Q2/19 and Q3/18 levels respectively, reflecting the Company's focus on cost control, higher volumes and lower energy costs.
    - At Primrose, as a result of strong execution the Company's high return pad additions came on ahead of schedule and on budget. Production from the pad additions were strong, beginning on September 16, 2019, utilizing available oil processing and steam capacity with managed production averaging approximately 13,600 bbl/d in September, offsetting production impacts from the planned turnaround at Horizon as part of the Company's curtailment optimization strategy.
- At Kirby, which now includes both Kirby South and Kirby North projects, Steam Assisted Gravity Drainage ("SAGD") production volumes averaged 31,260 bbl/d in Q3/19, a 9% increase over Q2/19 and a 13% decrease from Q3/18 levels. The increase from Q2/19 was primarily as a result of strong initial Kirby North production. Including energy costs, Kirby quarterly operating costs were strong at $8.69/bbl in Q3/19, reductions of 18% and 5% from Q2/19 and Q3/18 levels respectively, primarily as a result of the Company's focus on cost control, higher production volumes and lower energy costs.
    - Results from the first five months of the Company's solvent enhanced SAGD pilot at Kirby South continue to be positive, indicating that targeted reductions of 30% to 50% to Steam to Oil Ratios ("SORs") remain achievable. If success continues during the two year duration of the pilot, solvent enhanced SAGD has the potential to significantly reduce SORs, operating costs and greenhouse gas emissions by upwards of 50%, if fully commercialized.
    - At Kirby North, top tier execution and productivity have resulted in production averaging approximately 6,600 bbl/d in September 2019, exceeding production forecasts. Strong performance results are primarily due to improved well design, high plant reliability and other operational improvements. Production volumes will be managed as part of the Company's curtailment optimization strategy as the Company ramps up towards Kirby North's overall capacity of 40,000 bbl/d targeted in early 2021.
- At Jackfish, SAGD production volumes averaged 97,537 bbl/d in Q3/19. Including energy costs, Jackfish quarterly operating costs were strong at $9.44/bbl in Q3/19, approximately $3.00/bbl lower than operating cost indications for the asset at time of the acquisition primarily as a result of lower energy costs and synergies captured to date.
    - At Jackfish, pad additions that have been successfully drilled and not completed to date due to curtailments in Alberta have a production capability of 21,000 bbl/d. These pads require minimal capital of approximately $8 million to complete tie in activities that are targeted for Q4/19. Production from these pads is targeted to offset conventional production declines with long life low decline thermal in situ production, as the Company manages within its curtailment optimization strategy and targets to reach peak production in 2022.

▪ The Company’s annual 2019 thermal in situ production guidance remains unchanged and is targeted to range between 157,000 bbl/d - 172,000 bbl/d.

North America Natural Gas

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Natural gas production (MMcf/d)	**1,425**	1,482	1,489	**1,454**	1,506
Net wells targeting natural gas	**5**	2	6	**16**	15
Net successful wells drilled	**5**	2	6	**15**	15
Success rate	**100%**	100%	100%	**94%**	100%

▪ North America natural gas production was 1,425 MMcf/d in Q3/19, decreases of 4% from both Q2/19 and Q3/18 levels. The decreases were primarily due to natural field declines and reduced capital investment.

- Strong operating costs of $1.07/Mcf were achieved in Q3/19, decreases of 7% and 11% from Q2/19 and Q3/18 levels respectively. The operating cost decreases were primarily due to the Company's continued focus on cost control and the impact of increased processed volumes at strategically owned and operated facilities.
  - Septimus operating costs were strong at $0.26/Mcfe in Q3/19, decreases of 21% and 26% from Q2/19 and Q3/18 levels respectively. Focus on cost control supports the Company's high value liquids rich development at Septimus.
- The Company's natural gas reinjection pilot at Septimus commenced its first injection of 5 MMcf/d in Q2/19. Depending on results of the pilot, this technology has the potential to materially increase liquids recovery while storing natural gas in the reservoir, preserving the value of the natural gas for periods with higher market prices.
  - Initial results from the pilot are targeted for late 2019 with the potential to proceed with additional cycles at the same location. Given the opportunities for this process across Canadian Natural's vast liquids rich Montney land base, the Company is advancing readiness for a second pilot site within the Company's Greater Wembley area.
- In 2019 the Company strategically reallocated capital from crude oil projects to the Company's liquids rich Gold Creek assets, which are not subject to curtailment. In Q3/19, 2 net wells came on production averaging approximately 660 bbl/d and 4 MMcf/d per well, exceeding expectations by approximately 110 bbl/d or 20% per well.
- At Pine River, the Company's planned plant turnaround began in mid-September and was completed on November 6, 2019. The turnaround was designed to improve plant efficiency, run time, lower operating costs, and improve plant capability to 120 MMcf/d from current levels of 95 MMcf/d.
- In Q3/19, based upon corporate quarterly Natural Gas production, Canadian Natural used the equivalent of approximately 44% within its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 32% of the Company's Q3/19 natural gas production was exported to other North American markets and sold internationally, with the remaining 24% of the Company's Q3/19 natural gas production exposed to AECO/Station 2 pricing.
- The Company's annual 2019 corporate natural gas production guidance remains unchanged and is targeted to range between 1,485 MMcf/d - 1,545 MMcf/d.

International Exploration and Production

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil production (bbl/d)					
North Sea	**27,454**	27,594	28,702	**26,927**	24,940
Offshore Africa	**21,227**	23,650	18,802	**22,341**	18,812
Natural gas production (MMcf/d)					
North Sea	**20**	23	38	**24**	35
Offshore Africa	**24**	27	26	**26**	27
Net wells targeting crude oil	**3.0**	0.9	1.6	**5.5**	4.5
Net successful wells drilled	**3.0**	0.9	1.6	**5.5**	4.5
Success rate	**100%**	100%	100%	**100%**	100%

- International E&P production volumes were strong in Q3/19, exceeding quarterly production guidance, averaging 48,681 bbl/d, a decrease of 5% from Q2/19 and an increase of 2% over Q3/18 levels. The decrease from Q2/19 is primarily due to planned turnaround activities in the North Sea and natural field declines partially offset by strong performance from new wells. The increase from Q3/18 was primarily as a result of strong volumes from new wells drilled at Baobab and in the North Sea in late 2018 and 2019.
- International production volumes benefit from premium Brent pricing, generating significant free cash flow for the Company.
  - In the North Sea, production volumes of 27,454 bbl/d were achieved in Q3/19, comparable to Q2/19 and a 4% decrease from Q3/18 levels. The decrease from Q3/18 was primarily as a result of planned maintenance activities and natural field declines partly offset by volumes from new wells.

- Q3/19 operating costs in the North Sea averaged $37.11/bbl (£23.04/bbl), in line with Q2/19 and Q3/18 levels.
- The Company completed its 2019 drilling program in Q3/19 drilling 3 gross (3.0 net) high netback producer wells. Initial production from the total drilling program consisting of 5 gross (4.9 net) wells is exceeding expectations by approximately 1,300 bbl/d net per well in the quarter.

- Offshore Africa production volumes in Q3/19 averaged 21,227 bbl/d, a decrease of 10% from Q2/19 and an increase of 13% over Q3/18 levels. The decrease from Q2/19 was primarily as a result of natural field declines and turnaround activities in the quarter. The increase from Q3/18 was primarily as a result of production from new wells drilled late in 2018 and early in 2019 at Baobab, partially offset by natural field declines.
  - Côte d'Ivoire crude oil operating costs averaged $11.06/bbl (US$8.42/bbl) in Q3/19, an increase of 32% from Q2/19 and a decrease of 21% from Q3/18 levels primarily due to timing of liftings from various fields that have different cost structures.
  - Following the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural has a 20% working interest, the operator is preparing to commence a comprehensive 3D and 2D seismic acquisition program in Q4/19, with targeted completion in Q2/20.
    - The operator has contracted a rig with targeted spud of an exploration well in the first half of 2020. Depending on the results of this well, the operator may drill an additional well in 2020 to further define volumes and deliverability.
    - Canadian Natural is carried to a maximum gross cost of approximately US$300 million.

- The Company's annual 2019 International production guidance remains unchanged and is targeted to range from 46,000 bbl/d - 50,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Synthetic crude oil production (bbl/d) (1) (2)	**432,203**	374,500	394,382	**407,695**	419,161

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

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

- At the Company's world class Oil Sands Mining and Upgrading assets, production volumes were strong, at the upper end of production guidance, averaging 432,203 bbl/d of SCO in Q3/19, increases of 15% and 10% over Q2/19 and Q3/18 levels respectively. The increases were primarily as a result of strong operational performance as well as modified timing of the Horizon turnaround schedule as a part of the Company's curtailment optimization strategy.
  - Effective and efficient operations and high reliability resulted in strong quarterly operating costs of $20.05/bbl (US$15.18/bbl) of SCO in Q3/19, comparable to record low operating costs of $19.97/bbl (US$15.12/bbl) of SCO achieved in Q4/18, impressive results given the planned turnaround activities in the quarter. Q3/19 operating costs represent decreases of 17% and 12% from Q2/19 and Q3/18 levels respectively.
    - Total production costs were $784 million in Q3/19, $30 million lower than Q2/19. Production costs for the first nine months of 2019 were $2,420 million, a 6% or $150 million decrease from the comparable period in 2018, demonstrating the Company's focus on effective and efficient operations.
  - At the Albian mines, top tier operations combined with enhancing and optimization of equipment resulted in record gross bitumen production averaging approximately 318,000 bbl/d in September and October, forming a part of the Company’s curtailment optimization strategy during the Horizon turnaround. These results are significant as the two month average throughput was approximately 38,000 bbl/d or 14% above capability announced at the time of the acquisition. The Company continues to maximize value from acquired assets through lower operating costs and enhancing and optimizing production.
  - At Horizon, subsequent to quarter end the Company successfully completed a planned turnaround on schedule and under budget demonstrating strong execution by the Company's teams.
  - The Company continues to progress engineering work on a prudent basis for potential expansion opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The final investment decision on these opportunities will not be made until there is greater clarity on market access.

- The Company's annual 2019 Oil Sands Mining and Upgrading production guidance remains unchanged and is targeted to range between 405,000 bbl/d - 415,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 56.45**	$ 59.83	$ 69.50	**$ 57.06**	$ 66.79
WCS heavy differential as a percentage of WTI (%) (2)	**22%**	18%	32%	**21%**	33%
SCO price (US$/bbl)	**$ 56.87**	$ 59.96	$ 68.44	**$ 56.36**	$ 65.75
Condensate benchmark pricing (US$/bbl)	**$ 52.00**	$ 55.86	$ 66.82	**$ 52.79**	$ 66.28
Average realized pricing before risk management (C$/bbl) (3)	**$ 55.19**	$ 63.45	$ 57.89	**$ 57.49**	$ 54.26
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 0.99**	$ 1.11	$ 1.28	**$ 1.31**	$ 1.33
Average realized pricing before risk management (C$/Mcf)	**$ 1.64**	$ 1.98	$ 2.32	**$ 2.24**	$ 2.34

(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.

- Incremental egress of approximately 225,000 bbl/d to move incremental crude oil production out of the WCSB is targeted to be added over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Mainline enhancements are targeted to add approximately 85,000 bbl/d of capacity targeted to be available in December 2019.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in Q1/20.
  - The NWR Refinery is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available early in 2020.
  - Crude by rail volumes continue to be strong at approximately 310,000 bbl/d for the month of August 2019.
- Q3/19 differentials between WCS and WTI benchmark pricing narrowed from Q3/18 levels following the Government of Alberta's announcement of mandatory curtailments of crude oil production that came into effect January 1, 2019.
- AECO natural gas prices decreased in Q3/19 from Q2/19 and Q3/18 levels, reflecting pipeline egress constraints out of the basin as well as increased natural gas production in North America.
  - During Q3/19, TC Energy announced the Temporary Service Protocol ("TSP") on the Nova Gas Transmission Line that targets to manage system constraints during planned outages and maintenance during the summer months (April through October). TSP targets to be in place until October 2020, potentially resulting in reduced volatility of AECO benchmark pricing over that period.
- The NWR refinery, upon completion, targets to 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 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 July 2019, Canadian Natural published its 2018 Stewardship Report to Stakeholders, which is available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Highlights from the 2018 report are as follows:
- In the report, the Company confirmed that 100% of direct emissions from our Alberta oil sands in situ and mining operations were third party verified. The 2018 verification was completed by professional engineering firm GHD Limited.
  - Canadian Natural's corporate greenhouse gas ("GHG") emissions intensity has decreased by approximately 29% from 2012 to 2018, a material reduction in emissions intensity.
  - The Company's corporate GHG emissions intensity decreased in 2018 by approximately 29% from 2012 levels, including a reduction of approximately 37% at Horizon Oil Sands.
    - The Company's corporate GHG emissions intensity decreased in 2018 by approximately 5% from 2017 levels, including a reduction of approximately 18% in Oil Sands Mining and Upgrading.
  - Methane emissions have decreased 78% from 2012 to 2018 at the Company's Alberta primary heavy conventional crude oil operations.
  - In the Company's North America E&P segment, in 2018 natural gas flaring decreased by 4% and natural gas venting decreased by 6% from 2017 levels.
  - In 2018, in the Company's North America E&P segment, Canadian Natural abandoned 1,293 wells, an increase of 68% over 2017 levels, and submitted 1,012 reclamation certificates, an increase of approximately 67% over 2017 levels.
  - The Company reclaimed 1,383 hectares of land in 2018 in the Company's North America E&P segment, equivalent to approximately 1,700 Canadian football fields and a 9% increase over 2017 levels.
  - In the Oil Sands Mining and Upgrading segment, water use intensity decreased in 2018 by 30% from 2017 levels.
  - Approximately 75% of water used at Primrose was sourced from recycled produced water in 2018.
- Canadian Natural has invested over $3.4 billion in research and development from 2009 to 2018 year ended and continues to invest in technology to unlock reserves, become more effective and efficient, increase production and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders.
- 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 by way of carbon capture facilities at its 50% interest in the NWR refinery when on stream. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year, making the Company one of the largest CO_2 capturer and sequester for the oil and natural gas sector globally.
- 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 distance driven by its fleet 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.
  - The initial testing phase for the Company's IPEP pilot has concluded and results have been positive, with excellent recovery rates and evidence of stackable tailings. Given that the pilot continues to produce positive results, the Company is targeting to proceed with pilot enhancements in 2020.

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 1,176,361 BOE/d in Q3/19, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with Q3/19 production mix on a BOE/d basis of 49% light crude oil and SCO blends, 30% heavy crude oil blends and 21% natural gas.
- Canadian Natural delivered strong quarterly free cash flow of $1,471 million after net capital expenditures of $963 million, and dividend requirements of $447 million in Q3/19, reflecting the strength of our long life low decline asset base and our effective and efficient operations.
  - Balance sheet strength remains a focus and free cash flow was used to reduce debt levels in Q3/19 as the Company balances its free cash flow according to the defined free cash flow allocation policy. As a result gross long-term debt was reduced in Q3/19 by $1,018 million from Q2/19 levels.
  - Net long-term debt was reduced by $796 million to $22,313 million in Q3/19.
  - The Company utilized adjusted funds flow to repay and cancel $800 million of the $1,800 million non-revolving term loan facility; $1,000 million remained outstanding and fully drawn at quarter end.
    - Subsequent to quarter end the Company repaid and canceled an additional $500 million of the remaining $1,000 million non-revolving term loan; $500 million remains outstanding and fully drawn as at November 6, 2019.
  - Debt to book capitalization strengthened to 39.1% in Q3/19.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At September 30, 2019 the Company had approximately $4,680 million of available liquidity, including cash and cash equivalents, an increase of approximately $120 million over Q2/19 levels.
  - Canadian Natural is committed to returns to our shareholders, returning a total of $616 million in Q3/19, $447 million by way of dividends and $169 million by way of share purchases. In the first nine months of 2019, the Company has returned a total of $2,100 million to our shareholders, $1,299 million by way of dividends and $801 million by way of share purchases.
    - Share purchases for cancellation in the quarter totaled 5,050,000 common shares at a weighted average share price of $33.45.
    - Subsequent to quarter end, up to and including November 6, 2019, the Company executed on additional share purchases for cancellation of 1,350,000 common shares at a weighted average share price of $33.70.
    - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on January 1, 2020.
- In addition to the Company's 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, 2019, these financial levers include the Company's third party equity investments of $567 million, and cross currency swaps with a total value of $321 million.
- In 2018, the Board of Directors approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the policy, in 2019 the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures, dividends and large opportunistic acquisitions, 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. This policy was effective November 1, 2018.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Dr. M. Elizabeth Cannon to the Board of Directors of the Company, effective November 5, 2019. Dr. M. Elizabeth Cannon is currently President Emerita and Professor of Engineering at the University of Calgary having previously served at the University of Calgary as Dean of the Schulich School of Engineering from 2006-2010, President and Vice Chancellor from 2010 to 2018. Dr. Cannon is a fellow of the Royal Society of Canada and the Canadian Academy of Engineering, an associate of the National Academy of Engineering (US) and a corresponding member of the Mexican Academy of Engineering. She has served on the federal government's Science, Technology and Innovation Council, is past president of the U.S. Institute of Navigation, and is a past director of the Canada Foundation for Innovation. Dr. Cannon holds a Bachelor of Applied Sciences (Mathematics) from Acadia University as well as Bachelor of Science, Master of Science and a PhD in Geomatics Engineering, all from the University of Calgary. Dr. Cannon is a professional engineer and an APEGA member. She also holds Honorary Doctorates from 3 universities as well as an Honorary Bachelor of Business Administration from SAIT.

OUTLOOK

The Company targets annual 2019 production levels to average between 839,000 bbl/d and 888,000 bbl/d of crude oil and NGLs and between 1,485 MMcf/d and 1,545 MMcf/d of natural gas, before royalties. 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 2019 capital expenditures are targeted to be approximately $3.8 billion.

ADVISORY

Special Note Regarding non-GAAP Financial Measures

This press release includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company's performance.

Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non- operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The reconciliation “Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)" is presented in the Company’s MD&A.

Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure as it demonstrates the Company’s ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation “Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities” is presented in the Company’s MD&A.

Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business 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 used in Investing Activities” is presented in the Net Capital Expenditures section of the Company’s MD&A.

Free cash flow 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 from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends on common shares. The Company considers free cash flow a key measure in demonstrating the Company’s ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders, and to repay debt.

Adjusted EBITDA is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for interest, taxes, depletion, depreciation and amortization, stock based compensation expense (recovery), unrealized risk management gains (losses), unrealized foreign exchange gains (losses), and accretion of the Company’s asset retirement obligation. The Company considers adjusted EBITDA a key measure in evaluating its operating profitability by excluding non-cash items.

Debt to Adjusted EBITDA is a non-GAAP measure that is derived as the current and long-term portions of long-term debt, divided by the 12 month trailing Adjusted EBITDA, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Debt to cash flow is a non-GAAP measure that is derived as the current and long term portions of long-term debt, divided by the 12 month trailing adjusted funds flow, as defined above. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Debt to book capitalization is a non-GAAP measure that is derived as net current and long-term debt, divided by the book value of common shareholders' equity plus net current and long-term debt. The Company considers this ratio to be a key measure in evaluating the Company's ability to pay off its debt.

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 8 - Long-term Debt in the Company’s consolidated financial statements.

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ADVISORY

Special Note Regarding Forward-Looking Statements

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

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products; volatility of and assumptions regarding crude oil and natural gas prices; fluctuations in currency and interest rates; assumptions on which the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries’ ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries’ success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company’s provision for taxes; and other circumstances affecting revenues and expenses.

The Company’s operations have been, and in the future may be, affected by political developments and by national, federal, provincial and local laws and regulations such as restrictions on production, changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations. Should one or more of these risks or uncertainties materialize, or should any of the Company’s assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this MD&A could also have adverse effects on forward-looking statements. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by applicable law, the Company assumes no obligation to update forward-looking statements in this MD&A, whether as a result of new information, future events or other factors, or the foregoing factors affecting this information, should circumstances or the Company’s estimates or opinions change.

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, cash flows from operating activities, and cash flows used in investing activities, as determined in accordance with IFRS, as an indication of the Company's performance. The non-GAAP measure adjusted net earnings from operations is reconciled to net earnings, as determined in accordance with IFRS, in the “Financial Highlights” section of this MD&A. Additionally, the non-GAAP measure adjusted funds flow is reconciled to cash flows from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the “Net Capital Expenditures” section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

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

Production volumes and per unit statistics are presented throughout this MD&A on a “before royalties” or “company gross” basis, and realized prices are net of blending and feedstock costs and exclude the effect of risk management activities. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet (“Mcf”) of natural gas to one barrel (“bbl”) of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value. In addition, for the purposes of this MD&A, crude oil is defined to include the following commodities: light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), and SCO. Production on an “after royalties” or “company net” basis is also presented in this MD&A for information purposes only.

The following discussion and analysis refers primarily to the Company’s financial results for the three and nine months ended September 30, 2019 in relation to the comparable periods in 2018 and the second quarter of 2019. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com, provided that such guidance does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated November 6, 2019.

FINANCIAL HIGHLIGHTS

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

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

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

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

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

Adjusted Net Earnings from Operations, as Reconciled to Net Earnings

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

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

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

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

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

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

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

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

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

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

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

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

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

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

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

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

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

partially offset by:

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

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

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

partially offset by:

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

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

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

partially offset by:

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

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

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

Cash Flows from Operating Activities and Adjusted Funds Flow

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

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

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

Production Volumes

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

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

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

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

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"), the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the impact of the Company’s drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production in late 2018 due to low commodity prices in North America and production curtailments mandated by the Government of Alberta that came into effect January 1, 2019. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company’s allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at the Pine River processing facility, shut-in production due to third-party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company’s proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

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

Substantially all of the Company's production is sold based on US dollar benchmark pricing. Specifically, crude oil is marketed based on WTI and Brent indices. Canadian natural gas pricing is primarily based on Alberta AECO reference pricing, which is derived from the NYMEX reference pricing and adjusted for its basis or location differential to the NYMEX delivery point at Henry Hub. The Company's realized prices are highly sensitive to fluctuations in foreign exchange rates. Product revenue continued to be impacted by the volatility of the Canadian dollar as the Canadian dollar sales price the Company received for its crude oil and natural gas sales is based on US dollar denominated benchmarks.

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

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

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$64.51 per bbl for the nine months ended September 30, 2019, a decrease of 11% from US$72.35 per bbl for the nine months ended September 30, 2018. Brent averaged US$61.85 per bbl for the third quarter of 2019, a decrease of 18% from US$75.46 per bbl for the third quarter of 2018, and a decrease of 10% from US$68.36 per bbl for the second quarter of 2019.

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

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

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

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

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

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

DAILY PRODUCTION, before royalties

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

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

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

DAILY PRODUCTION, net of royalties

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

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

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

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

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

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

North America – Exploration and Production

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

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

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

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

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

North America – Oil Sands Mining and Upgrading

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

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

North Sea

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

Offshore Africa

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

International Guidance

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

International Crude Oil Inventory Volumes

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

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

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

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

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

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

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

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

North America

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

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

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

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

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

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

North Sea

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

Offshore Africa

Offshore Africa realized crude oil prices decreased 10% to average $86.79 per bbl for the nine months ended September 30, 2019 from $96.55 per bbl for the nine months ended September 30, 2018. Offshore Africa realized crude oil prices decreased 16% to average $82.97 per bbl for the third quarter of 2019 from $98.66 per bbl for the third quarter of 2018 and decreased 13% from $95.33 per bbl for the second quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and nine months ended September 30, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Nine Months Ended	
	Sep 30 2019	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Crude oil and NGLs ($/bbl) [1]					
North America	**$ 6.50**	$ 6.99	$ 7.44	**$ 6.57**	$ 6.87
North Sea	**$ 0.17**	$ 0.22	$ 0.31	**$ 0.18**	$ 0.23
Offshore Africa	**$ 4.43**	$ 3.85	$ 8.07	**$ 4.77**	$ 7.72
Average	**$ 6.02**	$ 6.35	$ 7.08	**$ 6.11**	$ 6.54
Natural gas ($/Mcf) [1]					
North America	**$ 0.01**	$ 0.07	$ 0.04	**$ 0.06**	$ 0.06
Offshore Africa	**$ 0.63**	$ 0.59	$ 1.20	**$ 0.69**	$ 1.07
Average	**$ 0.01**	$ 0.08	$ 0.05	**$ 0.07**	$ 0.08
Average ($/BOE) [1]	**$ 4.07**	$ 4.06	$ 4.44	**$ 3.98**	$ 4.10

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

North America

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

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

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

Offshore Africa

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

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

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

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

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

North America

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

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

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

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

North Sea

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

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

Offshore Africa

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

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

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

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

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

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

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

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

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

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

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

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

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

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

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

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

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

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

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

(2) Net of blending and feedstock costs.

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

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

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

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

ADJUSTED PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

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

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

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

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

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

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

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

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

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

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

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

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

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

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

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

MIDSTREAM AND REFINING

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

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

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

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

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

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

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

ADMINISTRATION EXPENSE

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

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

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

SHARE-BASED COMPENSATION

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

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered.

The Company recorded a $62 million share-based compensation expense for the nine months ended September 30, 2019, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within the share-based compensation expense for the nine months ended September 30, 2019 was $16 million related to performance share units granted to certain executive employees (September 30, 2018 – $8 million). For the nine months ended September 30, 2019, the Company charged $4 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (September 30, 2018 – $1 million recovered).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Nine Months Ended	
($ millions, except per BOE amounts and interest rates)	**Sep 30 2019**	Jun 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Expense, gross	**$ 239**	$ 214	$ 198	**$ 664**	$ 610
Less: capitalized interest	**8**	17	18	**45**	50
Expense, net	**$ 231**	$ 197	$ 180	**$ 619**	$ 560
$/BOE [(1)]	**$ 2.14**	$ 2.12	$ 1.85	**$ 2.11**	$ 1.92
Average effective interest rate	**3.9%**	4.1%	4.0%	**4.0%**	3.9%

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

Gross interest and other financing expense for the three and nine months ended September 30, 2019 increased from the comparable periods in 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Gross interest and other financing expense for the third quarter of 2019 was higher than the second quarter of 2019 primarily due to higher average debt levels in the third quarter as a result of the acquisition of assets from Devon that closed on June 27, 2019. Capitalized interest of $45 million for the nine months ended September 30, 2019 was primarily related to Kirby North and residual project activities at Horizon.

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

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

RISK MANAGEMENT ACTIVITIES

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

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

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

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

FOREIGN EXCHANGE

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

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

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

INCOME TAXES

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

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

(2) Petroleum Revenue Tax

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

The effective income tax rate for the three and nine months ended September 30, 2019 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

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

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

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

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

NET CAPITAL EXPENDITURES [1]

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

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

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

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

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

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

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

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

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

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

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

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

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

Drilling Activity (1)

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

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

(2) Includes bitumen wells.

North America

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

North Sea

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

LIQUIDITY AND CAPITAL RESOURCES

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

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

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

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

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

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

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

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

As at September 30, 2019, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt is dependent on factors discussed in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2018. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
  - During the third quarter of 2019, the Company repaid and cancelled $800 million of the $1,800 million non-revolving term credit facility scheduled to mature in May 2020. Subsequent to September 30, 2019, the Company repaid and cancelled an additional $500 million of the remaining $1,000 million outstanding on this non-revolving term credit facility.

- ◦ During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
- ◦ Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2019, the non-revolving term credit facilities were fully drawn.
- ◦ During the second quarter of 2019, the Company extended $330 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The remaining $2,095 million outstanding under this facility continues under the previous terms and matures in June 2021.The other $2,425 million revolving credit facility matures in June 2022. Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- ◦ During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.
- ◦ The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- ◦ In July 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

- ▪ Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- ▪ Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

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

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

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

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

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

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

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

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

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

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

Share Capital

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

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

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

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

COMMITMENTS AND CONTINGENCIES

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

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

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

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

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

In addition to the commitments disclosed above, the Company has entered into various agreements related to the engineering, procurement and construction of its various development projects. These contracts can be cancelled by the Company upon notice without penalty, subject to the costs incurred up to and in respect of the cancellation.

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

The Company is defendant and plaintiff in a number of legal actions arising in the normal course of business. In addition, the Company is subject to certain contractor construction claims. The Company believes that any liabilities that might arise pertaining to any such matters would not have a material effect on its consolidated financial position.

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, including the adoption of IFRS 16 "Leases", refer to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim consolidated financial statements for the three and nine months ended September 30, 2019.

IFRS 16 "Leases"

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

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

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

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

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

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

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

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

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the annual MD&A and the audited consolidated financial statements for the year ended December 31, 2018.

CONTROL ENVIRONMENT

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

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Sep 30 2019**	Dec 31 2018
ASSETS			
Current assets			
Cash and cash equivalents		**$ 176**	$ 101
Accounts receivable		**2,405**	1,148
Inventory		**1,151**	955
Prepaids and other		**309**	176
Investments	6	**567**	524
Current portion of other long-term assets	7	**70**	116
		4,678	3,020
Exploration and evaluation assets	3	**2,616**	2,637
Property, plant and equipment	4	**68,088**	64,559
Lease assets	5	**1,839**	—
Other long-term assets	7	**1,311**	1,343
		$ 78,532	$ 71,559
LIABILITIES			
Current liabilities			
Accounts payable		**$ 662**	$ 779
Accrued liabilities		**2,561**	2,356
Current income taxes payable		**85**	151
Current portion of long-term debt	8	**4,036**	1,141
Current portion of other long-term liabilities	5,9	**511**	335
		7,855	4,762
Long-term debt	8	**18,453**	19,482
Other long-term liabilities	5,9	**7,075**	3,890
Deferred income taxes		**10,355**	11,451
		43,738	39,585
SHAREHOLDERS' EQUITY			
Share capital	11	**9,314**	9,323
Retained earnings		**25,382**	22,529
Accumulated other comprehensive income	12	**98**	122
		34,794	31,974
		$ 78,532	$ 71,559

Commitments and contingencies (note 16).

Approved by the Board of Directors on November 6, 2019.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Sep 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Product sales	17	**$ 6,587**	$ 6,327	**$ 18,059**	$ 18,451
Less: royalties		**(427)**	(428)	**(1,089)**	(1,126)
Revenue		**6,160**	5,899	**16,970**	17,325
Expenses					
Production		**1,566**	1,585	**4,629**	4,837
Transportation, blending and feedstock		**1,248**	1,031	**3,283**	3,325
Depletion, depreciation and amortization	4,5	**1,426**	1,306	**3,996**	3,833
Administration		**95**	77	**249**	234
Share-based compensation	9	**7**	(85)	**62**	2
Asset retirement obligation accretion	9	**50**	47	**140**	140
Interest and other financing expense		**231**	180	**619**	560
Risk management activities	15	**(3)**	(29)	**49**	(116)
Foreign exchange loss (gain)		**115**	(168)	**(341)**	281
Gain on acquisition and revaluation of properties		**—**	(272)	**—**	(411)
Loss from investments	6,7	**61**	82	**150**	219
		4,796	3,754	**12,836**	12,904
Earnings before taxes		**1,364**	2,145	**4,134**	4,421
Current income tax expense	10	**161**	197	**403**	608
Deferred income tax expense (recovery)	10	**176**	146	**(1,088)**	446
Net earnings		**$ 1,027**	$ 1,802	**$ 4,819**	$ 3,367
Net earnings per common share					
Basic	14	**$ 0.87**	$ 1.48	**$ 4.04**	$ 2.75
Diluted	14	**$ 0.87**	$ 1.47	**$ 4.03**	$ 2.74

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Sep 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Net earnings	**$ 1,027**	$ 1,802	**$ 4,819**	$ 3,367
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 $6 million (2018 – $1 million) – three months ended; $12 million (2018 – $1 million) – nine months ended	**48**	8	**97**	(7)
Reclassification to net earnings, net of taxes of $2 million (2018 – $2 million) – three months ended; $5 million (2018 – $5 million) – nine months ended	**(13)**	(9)	**(36)**	(31)
	35	(1)	**61**	(38)
Foreign currency translation adjustment				
Translation of net investment	**36**	(44)	**(85)**	73
Other comprehensive income (loss), net of taxes	**71**	(45)	**(24)**	35
Comprehensive income	**$ 1,098**	$ 1,757	**$ 4,795**	$ 3,402

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Nine Months Ended **Sep 30 2019**	Sep 30 2018
Share capital	11		
Balance – beginning of period		**$ 9,323**	$ 9,109
Issued upon exercise of stock options		**148**	320
Previously recognized liability on stock options exercised for common shares		**17**	118
Purchase of common shares under Normal Course Issuer Bid		**(174)**	(154)
Balance – end of period		**9,314**	9,393
Retained earnings			
Balance – beginning of period		**22,529**	22,612
Net earnings		**4,819**	3,367
Purchase of common shares under Normal Course Issuer Bid	11	**(627)**	(720)
Dividends on common shares	11	**(1,339)**	(1,226)
Balance – end of period		**25,382**	24,033
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**122**	(68)
Other comprehensive income (loss), net of taxes		**(24)**	35
Balance – end of period		**98**	(33)
Shareholders' equity		**$ 34,794**	$ 33,393

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Sep 30 2019**	Three Months Ended Sep 30 2018	Nine Months Ended **Sep 30 2019**	Nine Months Ended Sep 30 2018
Operating activities					
Net earnings		**$ 1,027**	$ 1,802	**$ 4,819**	$ 3,367
Non-cash items					
Depletion, depreciation and amortization		**1,426**	1,306	**3,996**	3,833
Share-based compensation		**7**	(85)	**62**	2
Asset retirement obligation accretion		**50**	47	**140**	140
Unrealized risk management gain		**(2)**	(21)	**(4)**	(62)
Unrealized foreign exchange loss (gain)		**129**	(182)	**(323)**	158
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**—**	146
Gain on acquisition and revaluation of properties		**—**	(272)	**—**	(411)
Loss from investments	6,7	**68**	89	**171**	240
Deferred income tax expense (recovery)		**176**	146	**(1,088)**	446
Other		**(1)**	(20)	**(101)**	(5)
Abandonment expenditures		**(63)**	(57)	**(212)**	(197)
Net change in non-cash working capital		**(299)**	889	**(1,085)**	1,067
Cash flows from operating activities		**2,518**	3,642	**6,375**	8,724
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(1,182)**	(1,468)	**2,726**	(1,847)
Repayment of medium-term notes	8	**—**	—	**(500)**	—
Repayment of US dollar debt securities		**—**	—	**—**	(1,236)
Payment of lease liabilities	5	**(64)**	—	**(173)**	—
Issue of common shares on exercise of stock options		**30**	47	**148**	320
Purchase of common shares under Normal Course Issuer Bid		**(169)**	(433)	**(801)**	(874)
Dividends on common shares		**(447)**	(409)	**(1,299)**	(1,156)
Cash flows (used in) from financing activities		**(1,832)**	(2,263)	**101**	(4,793)
Investing activities					
Net expenditures on exploration and evaluation assets		**(3)**	(297)	**(73)**	(361)
Net expenditures on property, plant and equipment		**(897)**	(1,119)	**(2,563)**	(2,992)
Acquisition of Devon assets	4	**—**	—	**(3,412)**	—
Investment in other long-term assets		**—**	—	**—**	(28)
Net change in non-cash working capital		**(8)**	151	**(353)**	(391)
Cash flows used in investing activities		**(908)**	(1,265)	**(6,401)**	(3,772)
(Decrease) increase in cash and cash equivalents		**(222)**	114	**75**	159
Cash and cash equivalents – beginning of period		**398**	182	**101**	137
Cash and cash equivalents – end of period		**$ 176**	$ 296	**$ 176**	$ 296
Interest paid on long-term debt, net		**$ 263**	$ 224	**$ 674**	$ 707
Income taxes paid (received)		**$ 86**	$ (118)	**$ 372**	$ (195)

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 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 in the "Midstream and Refining" segment, the Company maintains certain 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 to upgrade and refine bitumen 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, 2018, 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, 2018.

2. CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

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

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

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

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

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

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

Further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at September 30, 2019 are shown in note 5.

Effective January 1, 2019, the Company's accounting policy for Leases is as follows:

At inception of a contract, the Company assesses whether a contract is, or contains a lease. A contract is, or contains a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether: the contract involves the use of an identified asset; the Company has the right to obtain substantially all of the economic benefits from the use of the asset throughout the period of use; and, the Company has the right to direct the use of the asset.

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract, which is the date that the lease asset is available to the Company. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease payments include fixed lease payments, variable lease payments based on indices or rates, residual value guarantees, and purchase options expected to be exercised. Subsequent to initial recognition, the lease liability is measured at amortized cost using the effective interest method. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees.

Lease assets are reported in a separate caption in the consolidated balance sheet. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheet.

Depreciation on lease assets used in the construction of property, plant and equipment is capitalized to the cost of those assets over their period of use until such time as the property, plant and equipment is substantially available for its intended use.

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

Effective January 1, 2019 on adoption of IFRS 16, the Company has applied the following significant accounting estimates and judgments in respect of lease accounting:

Purchase, extension and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgment to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

Changes in other accounting policies

In October 2017, the IASB issued amendments to IAS 28 "Investments in Associates and Joint Ventures" to clarify that the impairment provisions in IFRS 9 apply to financial instruments in an associate or joint venture that are not accounted for using the equity method, including long-term assets that form part of the net investment in the associate or the joint venture. The Company retrospectively adopted the amendments on January 1, 2019. These amendments did not have a significant impact on the Company's consolidated financial statements.

In June 2017, the IASB issued IFRIC 23 "Uncertainty over Income Tax Treatments". The interpretation provides guidance on how to reflect the effects of uncertainty in accounting for income taxes where IAS 12 is unclear. The Company adopted the interpretation on January 1, 2019. The interpretation did not have a significant impact on the Company's consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2018	$ 2,348	$ —	$ 37	$ 252	$ 2,637
Additions	**38**	**—**	**35**	**—**	**73**
Acquisition of Devon assets (note 4)	**91**	**—**	**—**	**—**	**91**
Transfers to property, plant and equipment	**(185)**	**—**	**—**	**—**	**(185)**
At September 30, 2019	**$ 2,292**	**$ —**	**$ 72**	**$ 252**	**$ 2,616**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2018	$ 67,007	$ 7,321	$ 5,471	$ 43,147	$ 441	$ 435	$ 123,822
Additions	**2,170**	**237**	**171**	**1,316**	**9**	**26**	**3,929**
Acquisition of Devon assets	**3,325**	**—**	**—**	**—**	**—**	**—**	**3,325**
Transfers from E&E assets	**185**	**—**	**—**	**—**	**—**	**—**	**185**
Disposals/derecognitions and other	**(393)**	**—**	**(1,515)**	**(166)**	**—**	**(3)**	**(2,077)**
Foreign exchange adjustments and other	**—**	**(219)**	**(175)**	**—**	**—**	**—**	**(394)**
At September 30, 2019	**$ 72,294**	**$ 7,339**	**$ 3,952**	**$ 44,297**	**$ 450**	**$ 458**	**$ 128,790**
Accumulated depletion and depreciation							
At December 31, 2018	$ 43,881	$ 5,735	$ 4,203	$ 4,981	$ 138	$ 325	$ 59,263
Expense	**2,309**	**174**	**172**	**1,126**	**11**	**18**	**3,810**
Disposals/derecognitions	**(393)**	**—**	**(1,515)**	**(166)**	**—**	**(3)**	**(2,077)**
Foreign exchange adjustments and other	**(3)**	**(152)**	**(138)**	**(1)**	**—**	**—**	**(294)**
At September 30, 2019	**$ 45,794**	**$ 5,757**	**$ 2,722**	**$ 5,940**	**$ 149**	**$ 340**	**$ 60,702**
Net book value							
- at September 30, 2019	**$ 26,500**	**$ 1,582**	**$ 1,230**	**$ 38,357**	**$ 301**	**$ 118**	**$ 68,088**
- at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

Project costs not subject to depletion and depreciation	**Sep 30 2019**	Dec 31 2018
Thermal Oil Sands	**$ 165**	$ 1,424

During the nine months ended September 30, 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, excluding the impact of the acquisition disclosed below, for net cash consideration of $62 million and assumed associated asset retirement obligations of $20 million. No net deferred income tax liabilities or pre-tax gains were recognized on these net transactions.

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, 2019, pre-tax interest of $45 million (September 30, 2018 – $50 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.0% (September 30, 2018 – 3.9%).

Acquisition of Thermal In Situ and Primary Heavy Crude Oil Assets

On June 27, 2019, the Company completed the acquisition of substantially all of the assets of Devon Canada Corporation ("Devon") including thermal in situ and heavy crude oil assets, for total cash purchase consideration of $3,412 million, subject to final closing adjustments.

In connection with the acquisition, the Company arranged a new $3,250 million committed term facility (note 8) and assumed certain product transportation commitments (note 16).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and operating costs, discount rates, and income taxes.

The following provides a summary of the net assets acquired and (liabilities) assumed relating to the acquisition:

Property, plant and equipment	$	**3,325**
Exploration and evaluation assets		**91**
Inventory, prepaids and other long-term assets		**195**
Accrued liabilities		**(21)**
Asset retirement obligations		**(178)**
Net assets acquired	$	**3,412**

The above amounts are estimates, and may be subject to change based on the receipt of new information.

As a result of the acquisition, revenue increased by approximately $770 million to $16,970 million and revenue, less production and transportation, blending and feedstock expenses increased by approximately $320 million to $9,058 million for the nine months ended September 30, 2019.

If the acquisition had been completed on January 1, 2019, the Company estimates that pro forma revenue, net of blending costs would have increased by approximately $1,010 million and pro forma revenue, net of blending costs, less production and transportation and feedstock expenses would have increased by approximately $670 million for the nine months ended September 30, 2019. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2019, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

5. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At January 1, 2019 (1)	$ 823	$ 332	$ 252	$ 132	$ 1,539
Additions	**444**	**40**	**12**	**6**	**502**
Depreciation	**(76)**	**(40)**	**(50)**	**(20)**	**(186)**
Derecognitions	**—**	**(4)**	**—**	**—**	**(4)**
Foreign exchange adjustments and other	**(4)**	**1**	**(9)**	**—**	**(12)**
At September 30, 2019	**$ 1,187**	**$ 329**	**$ 205**	**$ 118**	**$ 1,839**

(1) The Company adopted IFRS 16 "Leases" on January 1, 2019 using the modified retrospective approach. At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

Lease assets, by Segment

	Sep 30 2019
Exploration and Production	
North America	**$ 309**
North Sea	**50**
Offshore Africa	**164**
Oil Sands Mining and Upgrading	**1,217**
Head office	**99**
	$ 1,839

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at September 30, 2019 were as follows:

	Sep 30 2019
Lease liabilities	**$ 1,855**
Less: current portion	**244**
	$ 1,611

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings for the period are provided below:

	Three Months Ended Sep 30 2019	Nine Months Ended Sep 30 2019
Expenses relating to short-term leases (1)	**$ 110**	**$ 336**
Interest expense on lease liabilities	**$ 18**	**$ 52**
Variable lease payments not included in the measurement of lease liabilities	**$ 37**	**$ 89**

(1) In addition, during the three months ended September 30, 2019, the Company capitalized $70 million (nine months ended September 30, 2019 - $229 million) of short-term leases as additions to property, plant and equipment.

	Three Months Ended		Nine Months Ended	
		Sep 30 2019		**Sep 30 2019**
Total cash outflows for leases during the period [(1)]	$	**299**	$	**879**

(1) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

Impacts to the consolidated financial statements on transition

On transition to IFRS 16, the Company recognized $1,539 million of lease liabilities and corresponding lease assets. Lease liabilities were measured at the discounted value of lease payments using a weighted average incremental borrowing rate of 4.0% at January 1, 2019.

A reconciliation showing the impact of adoption of the standard is provided below:

		Jan 1 2019
Leases previously reported as commitments at December 31, 2018 [(1) (2)]	$	**1,430**
Impact of discounting		**(317)**
Leases previously reported as commitments, discounted at January 1, 2019		**1,113**
Leases recognized at adoption on January 1, 2019:		
Lease extension options and renewals reasonably certain to be exercised		**243**
Arrangements determined to be leases under IFRS 16		**83**
Leases entered into on behalf of a joint operation [(3)]		**100**
Lease liabilities recognized at January 1, 2019	$	**1,539**

(1) At December 31, 2018, the Company did not report any finance leases in accordance with its previous accounting policy for leases.

(2) Commitments for operating leases, previously reported in note 16, are now reported as part of lease liabilities and included in other long-term liabilities in note 9. Operating leases previously reported in note 16 have been aggregated into one line in the reconciliation table. Other non-lease commitments continue to be reported in the table in note 16.

(3) In accordance with the previous accounting for operating leases used in joint operations, the Company reported commitments and related expenses in accordance with the Company's proportionate interest in the joint operation. Under IFRS 16, where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability.

6. INVESTMENTS

As at September 30, 2019, the Company had the following investments:

		Sep 30 2019		Dec 31 2018
Investment in PrairieSky Royalty Ltd.	$	**418**	$	400
Investment in Inter Pipeline Ltd.		**149**		124
	$	**567**	$	524

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, measured at each reporting date. As at September 30, 2019, the Company's investment in PrairieSky was classified as a current asset.

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

	Three Months Ended				Nine Months Ended			
		Sep 30 2019		Sep 30 2018		**Sep 30 2019**		Sep 30 2018
Fair value (gain) loss from PrairieSky	$	**(2)**	$	73	$	**(18)**	$	212
Dividend income from PrairieSky		**(4)**		(5)		**(13)**		(13)
	$	**(6)**	$	68	$	**(31)**	$	199

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, measured at each reporting date. As at September 30, 2019, the Company's investment in Inter Pipeline was classified as a current asset.

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

	Three Months Ended				Nine Months Ended			
		Sep 30 2019		Sep 30 2018		**Sep 30 2019**		Sep 30 2018
Fair value (gain) loss from Inter Pipeline	$	**(18)**	$	14	$	**(25)**	$	23
Dividend income from Inter Pipeline		**(3)**		(2)		**(8)**		(8)
	$	**(21)**	$	12	$	**(33)**	$	15

7. OTHER LONG-TERM ASSETS

		Sep 30 2019		Dec 31 2018
Investment in North West Redwater Partnership	$	73	$	287
North West Redwater Partnership subordinated debt (1)		636		591
Prepaid cost of service toll		113		62
Risk management (note 15)		329		373
Other		230		146
		1,381		1,459
Less: current portion		70		116
	$	1,311	$	1,343

(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.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. Repairs to certain stainless steel piping were substantially complete in the third quarter of 2019 and the design modifications to the reactor burners in the gasifier unit are ongoing and will continue into the first quarter of 2020. In the third quarter of 2019, the light oil refinery entered a planned maintenance shutdown targeted to be completed in December 2019. Following startup, the light oil refinery will continue to process synthetic crude feedstock until the heavy oil units can reliably commence commercial processing of bitumen. As at September 30, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

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

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 16). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at September 30, 2019, the Company had recognized $113 million in prepaid cost of service tolls (December 31, 2018 - $62 million).

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

During the three months ended September 30, 2019, the Company recognized an equity loss from Redwater Partnership of $88 million (three months ended September 30, 2018 – loss of $2 million; nine months ended September 30, 2019 – loss of $214 million; nine months ended September 30, 2018 – loss of $5 million). The equity loss for the nine months ended September 30, 2019 includes the impact of $149 million of interest expense and $62 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units.

8. LONG-TERM DEBT

	Sep 30 2019	Dec 31 2018
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 2,403**	$ 831
Medium-term notes	**4,800**	5,300
	7,203	6,131
US dollar denominated debt, unsecured		
Bank credit facilities (September 30, 2019 – US$3,613 million; December 31, 2018 – US$2,954 million)	**4,785**	4,031
Commercial paper (September 30, 2019 – US$365 million; December 31, 2018 – US$104 million)	**483**	141
US dollar debt securities (September 30, 2019 – US$7,650 million; December 31, 2018 – US$7,650 million)	**10,131**	10,439
	15,399	14,611
Long-term debt before transaction costs and original issue discounts, net	**22,602**	20,742
Less: original issue discounts, net (1)	**17**	17
transaction costs (1) (2)	**96**	102
	22,489	20,623
Less: current portion of commercial paper	**483**	141
current portion of other long-term debt (1) (2)	**3,553**	1,000
	$ 18,453	$ 19,482

(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, 2019, the Company had in place revolving bank credit facilities of $4,975 million, of which $4,504 million was available. Additionally, the Company had in place fully drawn term credit facilities of $7,200 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,000 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 maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company's North Sea operations.

During the third quarter of 2019, the Company repaid and cancelled $800 million of the $1,800 million non-revolving term credit facility scheduled to mature in May 2020. Subsequent to September 30, 2019, the Company repaid and cancelled an additional $500 million of the remaining $1,000 million outstanding on this non-revolving term credit facility.

During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon (note 4). The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at September 30, 2019, the non-revolving term credit facilities were fully drawn.

During the second quarter of 2019, the Company extended $330 million of the $2,425 million revolving syndicated credit facility originally due June 2019 to June 2021. The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

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 revolving 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, 2019 was 2.5% (September 30, 2018 – 2.5%), and on total long-term debt outstanding for the nine months ended September 30, 2019 was 4.0% (September 30, 2018 – 3.9%).

As at September 30, 2019, letters of credit and guarantees aggregating to $444 million were outstanding.

Medium-Term Notes

During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.

In July 2019, the Company filed a new 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 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

In July 2019, the Company filed a new 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 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

9. OTHER LONG-TERM LIABILITIES

	Sep 30 2019	Dec 31 2018
Asset retirement obligations	**$ 5,334**	$ 3,886
Share-based compensation	**172**	124
Lease liabilities (note 5)	**1,855**	—
Risk management (note 15)	**4**	17
Deferred purchase consideration [1]	**95**	118
Other	**126**	80
	7,586	4,225
Less: current portion	**511**	335
	$ 7,075	$ 3,890

(1) Relates to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next four years.

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 discounted using a weighted average discount rate of 4.0% (December 31, 2018 – 5.0%) and inflation rates of up to 2% (December 31, 2018 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Sep 30 2019	Dec 31 2018
Balance – beginning of period	**$ 3,886**	$ 4,327
Liabilities incurred	**3**	19
Liabilities acquired, net	**198**	6
Liabilities settled	**(212)**	(290)
Asset retirement obligation accretion	**140**	186
Revision of cost, inflation rates and timing estimates	**146**	(111)
Change in discount rates	**1,199**	(334)
Foreign exchange adjustments	**(26)**	83
Balance – end of period	**5,334**	3,886
Less: current portion	**98**	186
	$ 5,236	$ 3,700

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 2019	Dec 31 2018
Balance – beginning of period	**$ 124**	$ 414
Share-based compensation expense (recovery)	**62**	(146)
Cash payment for stock options surrendered	**(1)**	(5)
Transferred to common shares	**(17)**	(120)
Charged to (recovered from) Oil Sands Mining and Upgrading, net	**4**	(19)
Balance – end of period	**172**	124
Less: current portion	**124**	92
	$ 48	$ 32

Included within share-based compensation liability as at September 30, 2019 was $29 million related to performance share units granted to certain executive employees (December 31, 2018 – $13 million).

10. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended Sep 30 2019	Three Months Ended Sep 30 2018	Nine Months Ended Sep 30 2019	Nine Months Ended Sep 30 2018
Current corporate income tax – North America	**$ 133**	$ 169	**$ 374**	$ 566
Current corporate income tax – North Sea	**15**	12	**72**	20
Current corporate income tax – Offshore Africa	**14**	22	**37**	43
Current PRT (1) – North Sea	**(4)**	(9)	**(89)**	(29)
Other taxes	**3**	3	**9**	8
Current income tax	**161**	197	**403**	608
Deferred corporate income tax	**176**	145	**(1,089)**	428
Deferred PRT (1) – North Sea	**—**	1	**1**	18
Deferred income tax	**176**	146	**(1,088)**	446
Income tax	**$ 337**	$ 343	**$ (685)**	$ 1,054

(1) Petroleum Revenue Tax

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

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Nine Months Ended Sep 30, 2019 Number of shares (thousands)		Amount
Balance – beginning of period	**1,201,886**	**$**	**9,323**
Issued upon exercise of stock options	**4,470**		**148**
Previously recognized liability on stock options exercised for common shares	**—**		**17**
Purchase of common shares under Normal Course Issuer Bid	**(22,150)**		**(174)**
Balance – end of period	**1,184,206**	**$**	**9,314**

Dividend Policy

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

On March 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share.

Normal Course Issuer Bid

On May 21, 2019, 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 59,729,706 common shares, over a 12-month period commencing May 23, 2019 and ending May 22, 2020. The Company's Normal Course Issuer Bid announced in May 2018 expired on May 22, 2019.

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

Stock Options

The following table summarizes information relating to stock options outstanding at September 30, 2019:

	Nine Months Ended Sep 30, 2019 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**46,685**	**$**	**37.92**
Granted	**15,924**	**$**	**34.79**
Surrendered for cash settlement	**(689)**	**$**	**34.80**
Exercised for common shares	**(4,470)**	**$**	**33.05**
Forfeited	**(2,777)**	**$**	**38.03**
Outstanding – end of period	**54,673**	**$**	**37.44**
Exercisable – end of period	**16,150**	**$**	**37.52**

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.

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

	Sep 30 2019	Sep 30 2018
Derivative financial instruments designated as cash flow hedges	**$ 74**	$ 9
Foreign currency translation adjustment	**24**	(42)
	$ 98	$ (33)

13. 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, 2019, the ratio was within the target range at 39.1%.

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 2019	Dec 31 2018
Long-term debt, net [1]	**$ 22,313**	$ 20,522
Total shareholders' equity	**$ 34,794**	$ 31,974
Debt to book capitalization	**39.1%**	39.1%

(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, 2019, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended		Nine Months Ended	
		Sep 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Weighted average common shares outstanding – basic (thousands of shares)		**1,185,589**	1,218,784	**1,193,184**	1,223,449
Effect of dilutive stock options (thousands of shares)		**1,533**	6,083	**2,143**	6,186
Weighted average common shares outstanding – diluted (thousands of shares)		**1,187,122**	1,224,867	**1,195,327**	1,229,635
Net earnings		**$ 1,027**	$ 1,802	**$ 4,819**	$ 3,367
Net earnings per common share	– basic	**$ 0.87**	$ 1.48	**$ 4.04**	$ 2.75
	– diluted	**$ 0.87**	$ 1.47	**$ 4.03**	$ 2.74

15. FINANCIAL INSTRUMENTS

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

	Sep 30, 2019				
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	**$ 2,405**	**$ —**	**$ —**	**$ —**	**$ 2,405**
Investments	**—**	**567**	**—**	**—**	**567**
Other long-term assets	**636**	**1**	**328**	**—**	**965**
Accounts payable	**—**	**—**	**—**	**(662)**	**(662)**
Accrued liabilities	**—**	**—**	**—**	**(2,561)**	**(2,561)**
Other long-term liabilities [(1)]	**—**	**(4)**	**—**	**(1,950)**	**(1,954)**
Long-term debt [(2)]	**—**	**—**	**—**	**(22,489)**	**(22,489)**
	$ 3,041	**$ 564**	**$ 328**	**$ (27,662)**	**$ (23,729)**

	Dec 31, 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	$ 1,148	$ —	$ —	$ —	$ 1,148
Investments	—	524	—	—	524
Other long-term assets	591	12	361	—	964
Accounts payable	—	—	—	(779)	(779)
Accrued liabilities	—	—	—	(2,356)	(2,356)
Other long-term liabilities [(1)]	—	(17)	—	(118)	(135)
Long-term debt [(2)]	—	—	—	(20,623)	(20,623)
	$ 1,739	$ 519	$ 361	$ (23,876)	$ (21,257)

(1) Includes $1,855 million of lease liabilities (December 31, 2018 – $nil) and $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 – $118 million).

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

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. 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, 2019			
	Carrying amount	**Fair value**		
Asset (liability) [(1) (2)]		**Level 1**	**Level 2**	**Level 3** [(4) (5)]
Investments [(3)]	**$ 567**	**$ 567**	**$ —**	**$ —**
Other long-term assets	**$ 965**	**$ —**	**$ 329**	**$ 636**
Other long-term liabilities	**$ (99)**	**$ —**	**$ (4)**	**$ (95)**
Fixed rate long-term debt [(6) (7)]	**$ (14,818)**	**$ (16,594)**	**$ —**	**$ —**

	Dec 31, 2018			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [4] [5]
Investments [3]	$ 524	$ 524	$ —	$ —
Other long-term assets	$ 964	$ —	$ 373	$ 591
Other long-term liabilities	$ (135)	$ —	$ (17)	$ (118)
Fixed rate long-term debt [6] [7]	$ (15,620)	$ (15,952)	$ —	$ —

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

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

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

(4) The fair value of the deferred purchase consideration included in other long-term liabilities is based on the present value of future cash payments.

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

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

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

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 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 2019	Dec 31 2018
Derivatives held for trading		
Foreign currency forward contracts	**$ 1**	$ 8
Natural gas AECO basis swaps	**(2)**	1
Natural gas AECO fixed price swaps	**(2)**	3
Crude oil WCS [1] differential swaps	**—**	(17)
Cash flow hedges		
Foreign currency forward contracts	**7**	70
Cross currency swaps	**321**	291
	$ 325	$ 356
Included within:		
Current portion of other long-term assets	**$ 17**	$ 92
Current portion of other long-term liabilities	**(4)**	(17)
Other long-term assets	**312**	281
	$ 325	$ 356

(1) Western Canadian Select

For the nine months ended September 30, 2019, the Company recognized a gain of $2 million (year ended December 31, 2018 – gain of $2 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 interest rate yield curves, and Canadian and United States forward 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.

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 2019**	Dec 31 2018
Balance – beginning of period	**$ 356**	$ 101
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**4**	35
Foreign exchange	**(103)**	260
Other comprehensive income (loss)	**68**	(40)
Balance – end of period	**325**	356
Less: current portion	**13**	75
	$ 312	$ 281

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

	Three Months Ended		Nine Months Ended	
	Sep 30 2019	Sep 30 2018	**Sep 30 2019**	Sep 30 2018
Net realized risk management (gain) loss	**$ (1)**	$ (8)	**$ 53**	$ (54)
Net unrealized risk management gain	**(2)**	(21)	**(4)**	(62)
	$ (3)	$ (29)	**$ 49**	$ (116)

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, 2019, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term			Volume	Weighted average price	Index
Natural Gas						
AECO basis swaps	Nov 2019	–	Mar 2020	95,000 MMbtu/d	US$0.96	NYMEX
AECO fixed price swaps	Apr 2020	–	Oct 2020	102,500 GJ/d	$1.51	AECO
			Oct 2019	115,000 GJ/d	$1.32	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, 2019, 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, 2019, 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 2019	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Oct 2019	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at September 30, 2019 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at September 30, 2019, the Company had US$4,531 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,978 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, 2019, 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, 2019, the Company had net risk management assets of $327 million with specific counterparties related to derivative financial instruments (December 31, 2018 – $361 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 of the Company's financial liabilities were as follows:

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	662	$	—	$	—	$	—
Accrued liabilities	$	2,561	$	—	$	—	$	—
Long-term debt (1)	$	4,040	$	3,112	$	7,067	$	8,383
Other long-term liabilities (2)	$	273	$	205	$	435	$	1,041
Interest and other financing expense (3)	$	936	$	786	$	1,771	$	5,038

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

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

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

16. COMMITMENTS AND CONTINGENCIES

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

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

(1) Subsequent to the adoption of IFRS 16, the Company reports its payments for lease liabilities in the maturity table in note 15.

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

(3) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,126 million of interest payable over the 30 year tolling period (see note 7).

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.

17. SEGMENTED INFORMATION

	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	
(millions of Canadian dollars, unaudited)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs	**2,661**	2,162	**6,797**	6,331	**218**	201	**563**	535	**226**	230	**538**	424	**3,105**	2,593	**7,898**	7,290
Natural gas	**199**	265	**823**	834	**9**	45	**45**	112	**16**	18	**52**	53	**224**	328	**920**	999
Other [(1)]	**1**	—	**6**	—	**1**	—	**3**	—	**3**	—	**6**	—	**5**	—	**15**	—
Total segmented product sales	**2,861**	2,427	**7,626**	7,165	**228**	246	**611**	647	**245**	248	**596**	477	**3,334**	2,921	**8,833**	8,289
Less: royalties	**(266)**	(247)	**(690)**	(685)	**—**	—	**(1)**	(1)	**(14)**	(22)	**(35)**	(42)	**(280)**	(269)	**(726)**	(728)
Segmented revenue	**2,595**	2,180	**6,936**	6,480	**228**	246	**610**	646	**231**	226	**561**	435	**3,054**	2,652	**8,107**	7,561
Segmented expenses																
Production	**624**	576	**1,797**	1,816	**103**	96	**270**	271	**37**	52	**79**	121	**764**	724	**2,146**	2,208
Transportation, blending and feedstock	**793**	613	**1,893**	2,046	**5**	6	**15**	18	**—**	—	**1**	1	**798**	619	**1,909**	2,065
Depletion, depreciation and amortization	**858**	795	**2,391**	2,353	**83**	53	**210**	169	**80**	69	**192**	139	**1,021**	917	**2,793**	2,661
Asset retirement obligation accretion	**27**	22	**68**	66	**6**	7	**21**	21	**1**	2	**4**	7	**34**	31	**93**	94
Risk management activities (commodity derivatives)	**7**	(32)	**36**	(19)	**—**	—	**—**	—	**—**	—	**—**	—	**7**	(32)	**36**	(19)
Gain on acquisition and revaluation of properties	**—**	(272)	**—**	(272)	**—**	—	**—**	(139)	**—**	—	**—**	—	**—**	(272)	**—**	(411)
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,309**	1,702	**6,185**	5,990	**197**	162	**516**	340	**118**	123	**276**	268	**2,624**	1,987	**6,977**	6,598
Segmented earnings (loss) before the following	**286**	478	**751**	490	**31**	84	**94**	306	**113**	103	**285**	167	**430**	665	**1,130**	963
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
(Gain) loss from investments																
Total non–segmented expenses																
Earnings before taxes																
Current income tax expense																
Deferred income tax expense (recovery)																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				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	
	2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs [2]	**3,117**	3,219	**8,707**	9,683	**21**	26	**62**	78	**81**	129	**336**	290	**6,324**	5,967	**17,003**	17,341
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**33**	32	**117**	111	**257**	360	**1,037**	1,110
Other [1]	**1**	—	**4**	—	**—**	—	**—**	—	**—**	—	**—**	—	**6**	—	**19**	—
Total segmented product sales	**3,118**	3,219	**8,711**	9,683	**21**	26	**62**	78	**114**	161	**453**	401	**6,587**	6,327	**18,059**	18,451
Less: royalties	**(147)**	(159)	**(363)**	(398)	**—**	—	**—**	—	**—**	—	**—**	—	**(427)**	(428)	**(1,089)**	(1,126)
Segmented revenue	**2,971**	3,060	**8,348**	9,285	**21**	26	**62**	78	**114**	161	**453**	401	**6,160**	5,899	**16,970**	17,325
Segmented expenses																
Production	**784**	842	**2,420**	2,570	**4**	5	**15**	16	**14**	14	**48**	43	**1,566**	1,585	**4,629**	4,837
Transportation, blending and feedstock [2]	**357**	265	**976**	913	**—**	—	**—**	—	**93**	147	**398**	347	**1,248**	1,031	**3,283**	3,325
Depletion, depreciation and amortization	**401**	385	**1,192**	1,161	**4**	4	**11**	11	**—**	—	**—**	—	**1,426**	1,306	**3,996**	3,833
Asset retirement obligation accretion	**16**	16	**47**	46	**—**	—	**—**	—	**—**	—	**—**	—	**50**	47	**140**	140
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**7**	(32)	**36**	(19)
Gain on acquisition and revaluation of properties	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(272)	**—**	(411)
Equity loss from investments	**—**	—	**—**	—	**88**	2	**214**	5	**—**	—	**—**	—	**88**	2	**214**	5
Total segmented expenses	**1,558**	1,508	**4,635**	4,690	**96**	11	**240**	32	**107**	161	**446**	390	**4,385**	3,667	**12,298**	11,710
Segmented earnings (loss) before the following	**1,413**	1,552	**3,713**	4,595	**(75)**	15	**(178)**	46	**7**	—	**7**	11	**1,775**	2,232	**4,672**	5,615
Non–segmented expenses																
Administration													**95**	77	**249**	234
Share-based compensation													**7**	(85)	**62**	2
Interest and other financing expense													**231**	180	**619**	560
Risk management activities (other)													**(10)**	3	**13**	(97)
Foreign exchange loss (gain)													**115**	(168)	**(341)**	281
(Gain) loss from investments													**(27)**	80	**(64)**	214
Total non–segmented expenses													**411**	87	**538**	1,194
Earnings before taxes													**1,364**	2,145	**4,134**	4,421
Current income tax expense													**161**	197	**403**	608
Deferred income tax expense (recovery)													**176**	146	**(1,088)**	446
Net earnings													**1,027**	1,802	**4,819**	3,367

(1) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts and other income of a trivial nature.
(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures (1)

	Nine Months Ended					
	Sep 30, 2019			Sep 30, 2018		
	Net expenditures	**Non-cash and fair value changes (2)**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes (2)	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America (3)	**$ 129**	**$ (185)**	**$ (56)**	$ 114	$ —	$ 114
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**35**	**—**	**35**	29	—	29
Oil Sands Mining and Upgrading (4)	**—**	**—**	**—**	218	(3)	215
	$ 164	**$ (185)**	**$ (21)**	$ 361	$ (3)	$ 358
Property, plant and equipment						
Exploration and Production						
North America (3)	**$ 4,372**	**$ 915**	**$ 5,287**	$ 1,953	$ (113)	$ 1,840
North Sea	**133**	**104**	**237**	73	220	293
Offshore Africa (5)	**145**	**(1,489)**	**(1,344)**	129	—	129
	4,650	**(470)**	**4,180**	2,155	107	2,262
Oil Sands Mining and Upgrading (6)	**1,004**	**146**	**1,150**	812	(178)	634
Midstream and Refining	**9**	**—**	**9**	11	—	11
Head office	**26**	**(3)**	**23**	14	—	14
	$ 5,689	**$ (327)**	**$ 5,362**	$ 2,992	$ (71)	$ 2,921

(1) This table provides a reconciliation of capitalized costs, reported in note 3 and note 4, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

(2) Derecognitions, asset retirement obligations, transfer of exploration and evaluation assets, and other fair value adjustments.

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

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

(5) Includes a derecognition of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in the first quarter of 2019.

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

Segmented Assets

	Sep 30 2019	Dec 31 2018
Exploration and Production		
North America	**$ 31,770**	$ 27,199
North Sea	**1,751**	1,699
Offshore Africa	**1,576**	1,471
Other	**70**	33
Oil Sands Mining and Upgrading	**41,728**	39,634
Midstream and Refining	**1,420**	1,413
Head office	**217**	110
	$ 78,532	$ 71,559

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 2019. 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, 2019:	
Interest coverage (times)	
Net earnings [1]	4.7x
Adjusted funds flow [2]	11.6x

(1) Net earnings plus income taxes and interest expense; divided by the sum of interest expense and capitalized interest.

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

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Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D

M. Elizabeth Cannon, O.C.

N. Murray Edwards, O.C.

Timothy W. Faithfull

Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

Steve W. Laut

Tim S. McKay

Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.

David A. Tuer

Annette M. Verschuren, O.C.

Officers

N. Murray Edwards
Executive Chairman

Steve W. Laut
Executive Vice-Chairman

Tim S. McKay
President

Darren M. Fichter
Chief Operating Officer, Exploration and Production

Scott G. Stauth
Chief Operating Officer, Oil Sands

Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance

Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations

Trevor J. Cassidy
Senior Vice-President, Thermal

Réal M. Cusson
Senior Vice-President, Marketing

Allan E. Frankiw
Senior Vice-President, Production

Jay E. Froc
Senior Vice-President, Oil Sands Mining and Upgrading

Ron K. Laing
Senior Vice-President, Corporate Development and Land

Pamela A. McIntyre
Senior Vice-President, Safety, Risk Management & Innovation

Bill R. Peterson
Senior Vice-President, Development Operations

Ken W. Stagg
Senior Vice-President, Exploration

Robin S. Zabek
Senior Vice-President, Exploitation

Paul M. Mendes
Vice-President, Legal, General Counsel and Corporate Secretary

Betty Yee
Vice-President, Land

CNR International (U.K.) Limited
Aberdeen, Scotland

David. B. Whitehouse
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

Computershare Trust Company of Canada
Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Investor Relations

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