Canadian Natural

FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2018 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2018 FOURTH QUARTER AND YEAR END RESULTS

Commenting on the Company's 2018 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "In 2018 we demonstrated the strength of our diverse and balanced asset base, and our ability to create value for Canadian Natural's shareholders throughout the commodity price cycle. Canadian Natural's continued focus on effective and efficient operations, ability to exercise capital flexibility and our mix of long life low decline assets resulted in cash flows from operating activities of over $10.0 billion and adjusted funds flow of over $9.0 billion in 2018, a significant achievement given industry challenges faced throughout the year."

Canadian Natural's President, Tim McKay, added, "We had a strong operational year in 2018 despite the volatility in commodity prices, as the Company was able to react quickly and strategically to changing market conditions. The Company achieved record annual production of approximately 1,079,000 BOE/d, delivering 12% production growth and 14% production per share growth over 2017 levels. Our industry leading Oil Sands Mining and Upgrading operations delivered record annual production of 426,190 bbl/d of Synthetic Crude Oil ("SCO") as a result of strong production at Horizon and a full year of production from the Athabasca Oil Sands Project. Additionally, record low annual adjusted operating costs of $21.05/bbl (US$16.24/bbl) of SCO and unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO were achieved as a result of safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies.

In 2018, crude oil price differentials widened due to market access restrictions and as a result, the Company made the proactive and strategic decisions throughout the year to voluntarily curtail crude oil production and reduce activity. Canadian Natural strongly supports the Government of Alberta's mandatory production curtailment program announced in late 2018 and as expected after this announcement, crude oil price differentials have since significantly narrowed. The Western Canadian Select ("WCS") differential index has narrowed to US$12.38/bbl for Q1/19 from the US$39.36/bbl experienced in Q4/18 and the differential between SCO and West Texas Intermediate ("WTI") benchmark pricing has narrowed to US $2.70/bbl for Q1/19 from the US$21.35/bbl experienced in Q4/18. As previously announced, the Company will continue to evaluate progress on export pipelines before enacting increases, if any, to its base 2019 capital budget.

Canadian Natural's mix of long life low decline assets and effective and efficient operations resulted in total Company Gross proved reserves increasing at the end of 2018 by 12% to 9.893 billion BOE, replacing 359% of 2018 production, with a reserves life index of 27.7 years. The Company's continued focus on continuous improvement, innovation and leveraging technology has lowered our overall cost structure, and as a result, proved finding, development and acquisition costs, including changes in future development capital, were excellent in 2018 and decreased from 2017 levels by 24% to $9.39/BOE."

Canadian Natural's Chief Financial Officer, Corey Bieber, continued, "Throughout 2018, Canadian Natural demonstrated its financial strength and resilience to market challenges through reduced long-term debt and upgraded credit ratings. Net earnings of approximately $2.6 billion and adjusted net earnings of approximately $3.3 billion were achieved in 2018, contributing to the reduction in absolute long-term debt by approximately $1.8 billion. Free cash flow was significant in the year at approximately $2.8 billion after net capital expenditures and dividend commitments. Canadian Natural's free cash flow allocation policy that came into effect November 1, 2018 was demonstrated in 2018 as approximately 46% of annual 2018 free cash flow was allocated to share purchases and approximately 54% was allocated to the Balance Sheet, including the impact of foreign exchange, working capital and other adjustments. Returns to shareholders were significant in 2018, totaling over $2.8 billion with over $1.2 billion returned through share purchases and approximately $1.6 billion returned through dividends.

Subsequent to year end, our Board of Directors approved a quarterly dividend increase of 12% to $0.375 per share, payable on April 1, 2019. The increase marks the 19th consecutive year of dividend increases, confirming our commitment to sustainable and increasing returns to shareholders."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Net earnings (loss)	**$ (776)**	$ 1,802	$ 396	**$ 2,591**	$ 2,397
Per common share – basic	**$ (0.64)**	$ 1.48	$ 0.32	**$ 2.13**	$ 2.04
– diluted	**$ (0.64)**	$ 1.47	$ 0.32	**$ 2.12**	$ 2.03
Adjusted net earnings (loss) from operations (1)	**$ (255)**	$ 1,354	$ 565	**$ 3,263**	$ 1,403
Per common share – basic	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.68**	$ 1.19
– diluted	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.67**	$ 1.19
Cash flows from operating activities	**$ 1,397**	$ 3,642	$ 1,438	**$ 10,121**	$ 7,262
Adjusted funds flow (2)	**$ 1,229**	$ 2,830	$ 2,307	**$ 9,088**	$ 7,347
Per common share – basic	**$ 1.02**	$ 2.32	$ 1.89	**$ 7.46**	$ 6.25
– diluted	**$ 1.02**	$ 2.31	$ 1.88	**$ 7.43**	$ 6.21
Cash flows used in investing activities	**$ 1,042**	$ 1,265	$ 1,074	**$ 4,814**	$ 13,102
Net capital expenditures (3)	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129
Daily production, before royalties					
Natural gas (MMcf/d)	**1,488**	1,553	1,656	**1,548**	1,662
Crude oil and NGLs (bbl/d)	**833,358**	801,742	744,100	**820,778**	685,236
Equivalent production (BOE/d) (4)	**1,081,368**	1,060,629	1,020,094	**1,078,813**	962,264

(1) Adjusted net earnings (loss) 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 Management's Discussion and Analysis ("MD&A").

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that the Company considers key as it demonstrates the Company's ability to 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 MD&A.

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

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

ANNUAL HIGHLIGHTS

- Net earnings of $2,591 million were realized in 2018, an increase of $194 million over 2017 levels. Adjusted net earnings of $3,263 million were achieved in 2018, a $1,860 million increase over 2017 levels.
- Cash flows from operating activities were $10,121 million in 2018, an increase of $2,859 million compared to 2017 levels.
- Canadian Natural generated significant annual adjusted funds flow of $9,088 million in 2018, an increase of 24% or $1,741 million over 2017 levels. The increase year over year was primarily due to increased Synthetic Crude Oil ("SCO") production volumes, higher netbacks in the Oil Sands Mining and Upgrading segment and higher netbacks in the International segment, partially offset by lower crude oil, NGLs and natural gas netbacks in the North America Exploration and Production ("E&P") segment, and significantly lower crude oil pricing in Q4/18.
  - On December 2, 2018, the Government of Alberta announced the mandatory production curtailment program that resulted in crude oil differentials narrowing to more normalized levels. Subsequent to year end, the Western Canadian Select ("WCS") differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18 and the differential between SCO and West Texas Intermediate ("WTI") benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.

- Cash flows used in investing activities were $4,814 million in 2018, a decrease of $8,288 million compared to 2017 levels as a result of acquisitions completed in 2017.
- Consistent with the Company's four pillar strategy, the Company maintained balance in the allocation of its annual adjusted funds flow throughout 2018:
  - The Company remained disciplined in its economic resource development investments with annual net capital expenditures of $4,731 million, or approximately $4,490 million, excluding net acquisitions.
  - The Company reduced long-term debt by approximately $1,835 million, including the impact of foreign exchange, working capital and other adjustments. As a result, debt to adjusted EBITDA strengthened to 2.0x and debt to book capitalization improved to 39.1%.
  - Returns to shareholders are a key focus for Canadian Natural as the Company returned a total of $2,844 million in the year, $1,562 million by way of dividends and $1,282 million by way of share purchases.
    - Share purchases for cancellation totaled 30,857,727 common shares at a weighted average share price of $41.56.
    - Subsequent to year end and up to and including March 6, 2019, the Company executed on additional share purchases of 4,340,000 common shares for cancellation at a weighted average share price of $35.86.
    - Dividends increased 22% from 2017 levels to $1.34 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 12% to $0.375 per share, payable on April 1, 2019. The increase marks the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's sustainability and robustness of the asset base driving the ability to generate significant adjusted funds flow.
  - The Company executed on opportunistic net acquisitions of $241 million, including net exploration and evaluation proceeds of $74 million. These core area acquisitions add significant future value to the Company's long life low decline asset portfolio.
- Canadian Natural delivered annual adjusted funds flow in excess of net capital expenditures of approximately $4,360 million, including the deferred discounted purchase consideration related to the Joslyn acquisition. After dividend requirements, annual free cash flow totaled approximately $2,795 million.
  - Demonstrating Canadian Natural's commitment to balanced capital allocation, the Company allocated approximately 46% of annual 2018 free cash flow, after dividends, to share purchases and approximately 54% to the Company's Balance Sheet, including the impact of foreign exchange, working capital and other adjustments.
- The Company achieved record annual production volumes of 1,078,813 BOE/d in 2018, an increase of 12% over 2017 levels. The increase from 2017 was mainly due to a full year of Horizon Phase 3 production and a full year of production from acquisitions completed in 2017, partially offset by declines in natural gas production along with voluntary natural gas and crude oil curtailments, shut ins and reduced drilling activity.
  - Annual BOE production per share growth was strong, increasing 14% when compared to 2017 levels.
- Canadian Natural's annual corporate crude oil and NGLs production reached a record 820,778 bbl/d, an increase of 20% over 2017 levels. The increase from 2017 was mainly due to Horizon Phase 3 operating at high utilization rates and a full year of production from acquisitions completed in 2017, partially offset by voluntary crude oil production curtailments, shut ins and reduced drilling activity.
- North America crude oil and NGLs, excluding thermal in situ oil sands, averaged 243,122 bbl/d in 2018, representing a 2% increase from 2017 levels mainly due to the successful integration of acquired assets at Pelican Lake, partially offset by the impact of proactive measures taken to reduce annual drilling in the second half of the year by approximately 100 net wells, delay completion and ramp up of new wells, and voluntarily curtail crude oil production.
  - In 2018, Pelican Lake crude oil production averaged 63,082 bbl/d, a 22% increase when compared to 2017 levels primarily due to assets acquired in late 2017. In 2018, polymer flood restoration on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood.
- At the Company's world class Oil Sands Mining and Upgrading assets, industry leading operations provided record annual production of 426,190 bbl/d of SCO, an increase of 51% from 2017 levels. The increase in production was primarily due to a full year of Horizon Phase 3 operations and the acquisition of the Athabasca Oil Sands Project ("AOSP") in 2017.
  - The Company realized record low annual unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO in 2018, a decrease of 13% from 2017 levels. Operating costs were top tier, below the midpoint of guidance and

were achieved through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies. After normalizing for planned turnaround downtime, operating costs decreased 10% to $21.05/bbl (US$16.24/bbl) of SCO compared to $23.40/bbl of SCO in 2017.

- In the Company's thermal in situ operations, pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted to add approximately 10,000 bbl/d in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
- At Kirby North, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule. The project now targets first steam in late Q2/19 with the flexibility to ramp up production in late Q3/19. Cost performance remains on budget with the overall project 87% complete. Kirby North's overall capacity of 40,000 bbl/d of Steam Assisted Gravity Drainage ("SAGD") production is targeted for late 2020.
- International E&P annual production volumes were strong in 2018, averaging 43,627 bbl/d, comparable to 2017 levels. International production volumes receive Brent pricing, which is not subject to the price differentials experienced in Alberta. 2018 Brent pricing averaged US$71.12/bbl, a 31% increase from 2017 pricing of US$54.38/bbl, generating significant adjusted funds flow in the Company's International segment.
  - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net producer wells drilled in the year. Current light crude oil production continues to be strong at approximately 1,250 bbl/d net per well.
  - In 2018, the Company successfully drilled 1.7 net producer wells at Baobab. Current light crude oil production is exceeding sanctioned expectations at approximately 2,500 bbl/d net per well. As a result of the successful 2018 drilling program at Baobab, Canadian Natural targets to drill one additional producer well at Baobab in 2019.
  - Subsequent to year end, the operator of the South Africa exploration well announced a discovery of significant gas condensate and targets to evaluate further exploration wells on Block 11B/12B located offshore South Africa. Canadian Natural expects the cost of the current exploration well to be fully carried. In 2019, the operator targets to acquire 3D seismic on the Block.
- Balance sheet strength and strong financial performance were demonstrated in 2018 through reduced long-term debt and upgraded credit ratings.
  - In 2018, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook. Additionally, Standard & Poor's revised the Company's rating outlook to BBB+/stable from BBB+/negative.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At December 31, 2018 the Company had approximately $4,824 million of available liquidity, including cash and cash equivalents, an increase of approximately $574 million from 2017 levels.

RESERVES UPDATE

- Canadian Natural's crude oil, SCO, bitumen, natural gas and NGL reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators. The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2018 (all reserves values are Company Gross unless stated otherwise).
  - Total proved reserves increased 12% to 9.893 billion BOE. The increase is largely driven by the addition of the Horizon South Pit, and pad additions and improved recovery at Primrose.
  - Proved developed producing reserves additions and revisions are 1.109 billion BOE, replacing 2018 production by 281%. The total proved developed producing BOE reserves life index is 21.3 years.
  - Proved reserves additions and revisions are 1.416 billion BOE, replacing 2018 production by 359%. The total proved BOE reserves life index is 27.7 years.
  - Proved plus probable reserves increased 13% to 13.382 billion BOE. Proved plus probable reserves additions and revisions are 1.910 billion BOE, replacing 2018 production by 485%. The total proved plus probable BOE reserves life index is 37.4 years.
  - Proved finding, development and acquisition ("FD&A") costs, excluding changes in future development capital ("FDC"), are $3.11/BOE and proved plus probable FD&A costs, excluding changes in FDC, are $2.31/BOE. Proved FD&A costs, including changes in FDC, are $9.39/BOE and proved plus probable FD&A costs, including changes in FDC, are $10.79/BOE.

- Proved net present value of future net revenues, before income tax, discounted at 10%, is $106.6 billion, a 19% increase from the year end 2017 evaluation. Proved plus probable net present value is $131.0 billion, a 14% increase from year end 2017.

FOURTH QUARTER HIGHLIGHTS

- Due to a significant decline in crude oil pricing, largely driven by an oversupplied domestic market environment, lack of takeaway capacity and increased global supply, the Company incurred a net loss of $776 million in Q4/18 and an adjusted net loss from operations of $255 million.
- Cash flows from operating activities were $1,397 million and adjusted funds flow were $1,229 million in Q4/18. Adjusted funds flow decreased by $1,601 million from Q3/18 levels and by $1,078 million from Q4/17 levels due to significantly wider crude oil price differentials, largely driven by market access restrictions.
- On December 2, 2018, the Government of Alberta announced the mandatory production curtailment program that resulted in crude oil differentials narrowing to more normalized levels. Subsequent to year end, the WCS differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.
- The Company's production volumes in Q4/18 averaged 1,081,368 BOE/d, a 2% increase over Q3/18 levels and a 6% increase over Q4/17 levels. The increase from the comparable quarters was mainly due to strong production from the Oil Sands Mining and Upgrading segment partially offset by reduced drilling activity and the impact of strategic actions taken to voluntarily curtail primary heavy and thermal in situ crude oil production totalling approximately 24,500 bbl/d.
- At the Company's world class Oil Sands Mining and Upgrading assets, top tier operations provided quarterly production of 447,048 bbl/d of SCO, an increase of 39% over Q4/17 levels mainly due to production from the Horizon Phase 3 expansion and a 13% increase over Q3/18 levels as operations resumed following a major planned turnaround at Horizon.
  - The Company realized industry leading operating costs of $19.97/bbl (US$15.12/bbl) of SCO in Q4/18, through safe, steady and reliable operations, high utilization, and leveraging expertise to capture synergies. These results were comparable to Q3/18 levels and a 20% decrease from Q4/17 levels.
- Offshore Africa quarterly production volumes averaged 22,185 bbl/d in Q4/18, an 18% increase over Q3/18 and a 14% increase over Q4/17 levels. The increase in production from the comparable periods was primarily due to production from new wells drilled at Baobab in 2018, partially offset by natural field declines. International production receives Brent pricing that averaged US$67.45/bbl in Q4/18, a 10% increase from Q4/17 pricing of US$61.46/bbl, generating significant adjusted funds flow in the Company's international segment.
- Share purchases for cancellation in the quarter totaled 10,845,600 common shares at a weighted average share price of $37.67.

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

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

Drilling Activity

	Year Ended Dec 31			
	2018		2017	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**513**	**483**	529	495
Natural gas	**25**	**18**	27	21
Dry	**9**	**9**	7	7
Subtotal	**547**	**510**	563	523
Stratigraphic test / service wells	**717**	**615**	289	289
Total	**1,264**	**1,125**	852	812
Success rate (excluding stratigraphic test / service wells)		**98%**		99%

- The Company's total crude oil and natural gas drilling program of 510 net wells for the year ended December 31, 2018, excluding strat/service wells, was a decrease of 13 net wells from the same period in 2017. The Company's drilling levels reflect the disciplined capital allocation process and proactive actions to improve execution and control costs by balancing overall drilling levels throughout the year.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs production (bbl/d)	**240,942**	247,314	259,416	**243,122**	239,309
Net wells targeting crude oil	**62**	140	123	**361**	472
Net successful wells drilled	**61**	135	120	**353**	466
Success rate	**98%**	96%	98%	**98%**	99%

- North America crude oil and NGLs averaged 243,122 bbl/d in 2018, representing a 2% increase from 2017 levels mainly due to the successful integration of acquired assets at Pelican Lake, partially offset by the impact of proactive measures taken to reduce annual drilling in the second half of the year by approximately 100 net wells, delay completion and ramp up of new wells, and voluntarily curtail crude oil production.
- Canadian Natural's primary heavy crude oil production averaged 86,312 bbl/d in 2018, a 10% decrease from 2017 levels primarily due to strategic actions taken to reduce drilling, delay completion and ramp of new wells and voluntarily curtail primary heavy crude oil production due to widening price differentials driven by market access restrictions.
  - In the second half of 2018, to maximize value as a result of widening price differentials, Canadian Natural implemented proactive and strategic decisions to reallocate capital from primary heavy crude oil assets to light crude oil assets. As a result, the Company drilled 137 fewer net primary heavy crude oil wells and delayed completion on 29 net wells in the year, compared to the original budget.
  - At the Company's Smith primary heavy crude oil play, production from 6 net multilateral wells drilled in 2018 continues to exceed sanctioned expectations with current rates of approximately 300 bbl/d per well and lower than expected decline rates. There is significant development potential at Smith for approximately 118 net horizontal multilateral wells on the Company's 19 net sections and the Company targets to evaluate the future development opportunities at Smith as market access improves.
  - Operating costs of $16.60/bbl were achieved in the Company's primary heavy crude oil operations in 2018, a 6% increase from 2017 levels, strong results given lower production volumes due to the Company's decision to curtail production.
- North America light crude oil and NGL production averaged 93,728 bbl/d in 2018, an increase of 2% from 2017 levels. The increase from 2017 is primarily as a result of reallocation of capital from primary heavy crude oil to light crude oil drilling projects.
  - The Company successfully drilled 99 net light crude oil wells in 2018, 32 net wells above budget as the Company reallocated capital from primary heavy crude oil to light crude oil in the second half of 2018. Production from the additional light crude oil wells came on in late Q4/18 and in early Q1/19. Highlights from the drilling program are as follows:
    - Within the greater Wembley area, results continue to exceed expectations. The Company drilled 27 net wells in 2018, 14 of which came on production with initial 30 day liquids production rates averaging approximately 600 bbl/d per well. The remaining wells are targeted to come on production in Q1/19. Within the greater Wembley area, the Company has identified 155 net Montney sections and 365 incremental potential premium light crude oil and liquids rich well locations.
      - The Company's core Wembley light crude oil play, included within the greater Wembley area identified above, has 88 net sections of land and 213 potential premium well locations. In the core Wembley light crude oil area, production results have been strong as the Company completed 12 net wells in 2018, 7 of which came on production late in the year with initial 30 day liquids production rates averaging approximately 785 bbl/d per well. The remaining 5 wells are targeted to come on production in Q1/19.
    - In Southeast Saskatchewan and Manitoba, the Company drilled 33 net light crude oil wells in 2018, an additional 18 wells than budgeted as a result of the strategic decision to shift capital to light crude oil assets. Currently, production from these wells is averaging 2,750 bbl/d, in-line with expectations. Production from these Saskatchewan and Manitoba wells are less impacted by the price differentials experienced in Alberta.
  - In 2018, operating costs of $15.29/bbl were realized in the Company's North America light crude oil and NGL areas.
- Pelican Lake annual production averaged 63,082 bbl/d, an increase of 22% from 2017 levels, primarily as a result of the Company's successful integration of acquired assets in late 2017. Canadian Natural's long life low decline Pelican Lake assets along with the Company's industry leading polymer flood technology are driving significant value.
  - Polymer flood restoration in 2018 on the acquired lands was completed ahead of schedule, where approximately 62% of acquired lands are now under polymer flood.
  - In Q4/18, the Company drilled 4 net strategic wells with initial production results of approximately 100 bbl/d per well, exceeding sanctioned expectations. The Company has identified potential opportunities for an additional 31 producer wells.
  - Facility consolidation is targeted to be complete in early Q2/19, resulting in targeted operating cost savings of approximately $6 million per year.

- Strong operating costs of $6.72/bbl were achieved in 2018 at Pelican Lake.

▪ The Company's 2019 North America E&P crude oil and NGL annual production guidance remains unchanged and is targeted to range between 221,000 bbl/d - 241,000 bbl/d.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Bitumen production (bbl/d)	**102,112**	112,542	124,121	**107,839**	120,140
Net wells targeting bitumen	**41**	41	5	**125**	27
Net successful wells drilled	**40**	41	5	**124**	27
Success rate	**98%**	100%	100%	**99%**	100%

▪ Thermal in situ annual production volumes averaged 107,839 bbl/d in 2018, a 10% decrease from 2017 levels, primarily due to proactive and strategic decisions to voluntarily curtail production volumes of approximately 4,200 bbl/d.
  - At Primrose, 2018 production volumes averaged approximately 70,000 bbl/d, a decrease of 14% from 2017 levels, primarily as a result of proactive and strategic decisions to voluntarily curtail production volumes and the cyclical nature of thermal production. Including energy costs, operating costs were $14.03/bbl in 2018, an increase of 14% from 2017 levels, reflecting lower volumes due to voluntary curtailment and increased carbon tax and energy costs in 2018.
    - Pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted to add approximately 10,000 bbl/d in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
  - At Kirby South, SAGD production volumes of 35,061 bbl/d were achieved in 2018, a 3% decrease from 2017 levels. Including energy costs, Kirby South achieved strong 2018 annual operating costs of $9.54/bbl, comparable to $9.50/bbl in 2017.
  - At Kirby North, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule. The project now targets first steam in late Q2/19 with the flexibility to ramp up production in late Q3/19. Cost performance remains on budget with the overall project 87% complete. Kirby North's overall capacity of 40,000 bbl/d of SAGD production is targeted for late 2020.

▪ The Company's 2019 thermal in situ annual production guidance remains unchanged and is targeted to range between 104,000 bbl/d - 124,000 bbl/d.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Natural gas production (MMcf/d)	**1,441**	1,489	1,596	**1,490**	1,601
Net wells targeting natural gas	**3**	6	2	**18**	22
Net successful wells drilled	**3**	6	2	**18**	21
Success rate	**100%**	100%	100%	**100%**	95%

▪ North America natural gas production was 1,490 MMcf/d in 2018, a decrease of 7% from 2017 levels, primarily due to strategic decisions to reduce drilling and development activities, curtail and shut in production as a result of low natural gas prices, reduced production rates at the Pine River plant, operated by a third party, and natural field declines.

- Deferred capital and development activity, including recompletions and workovers of certain natural gas assets, along with production shut ins resulted in a production impact of approximately 79 MMcf/d in 2018.
- Additionally, the Company's natural gas production capability was reduced by approximately 48 MMcf/d in 2018 due to restrictions at the Pine River plant, operated by a third party.

▪ The Pine River plant, operated by a third party, is currently operating at restricted rates of approximately 90 MMcf/d. As previously announced, Canadian Natural agreed to acquire the facility from the third party and is awaiting regulatory approval. The Company completed an engineering cost assessment of the plant and has determined the optimal plant capacity to be 120 MMcf/d compared to the previous estimate of 145 MMcf/d and targets to complete the work in Q3/19.

▪ Operating costs of $1.25/Mcf were realized in 2018, an increase of 5% from 2017 levels, strong results given lower natural gas production volumes.

▪ The Company's natural gas reinjection pilot at Septimus has received regulatory approval and is targeted to commence with first injection of 5 MMcf/d in late Q2/19. If successful, natural gas reinjection has the potential to add significant value by unlocking liquids rich development without producing incremental natural gas in a constrained takeaway environment.

▪ In 2018, Canadian Natural used the equivalent of approximately 35% of its total corporate natural gas production in its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 32% of the Company's total 2018 natural gas production was exported to other North American markets and sold internationally at an average price of $4.32/Mcf. The remaining 33% of the Company's 2018 natural gas production was exposed to AECO/Station 2 pricing.

▪ The Company’s 2019 corporate natural gas annual 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			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil production (bbl/d)					
North Sea	**21,071**	28,702	19,548	**23,965**	23,426
Offshore Africa	**22,185**	18,802	19,519	**19,662**	20,335
Natural gas production (MMcf/d)					
North Sea	**22**	38	37	**32**	39
Offshore Africa	**25**	26	23	**26**	22
Net wells targeting crude oil	**1.1**	1.6	—	**5.6**	1.8
Net successful wells drilled	**1.1**	1.6	—	**5.6**	1.8
Success rate	**100%**	100%	—	**100%**	100%

▪ International E&P annual production volumes were strong in 2018, averaging 43,627 bbl/d, comparable to 2017 levels. International production volumes receive Brent pricing, which is not subject to the price differentials experienced in Alberta. 2018 Brent pricing averaged US$71.12/bbl, a 31% increase from 2017 pricing of US$54.38/bbl, generating significant adjusted funds flow in the Company's international segment.

- In the North Sea, production volumes of 23,965 bbl/d were achieved in 2018, an increase of 2% over 2017 levels, primarily due to the successful 2018 drilling program, partially offset by natural field declines.
    - The 2018 drilling program in the North Sea was successfully completed on time and on budget with 3.9 net producer wells drilled in the year. Current light crude oil production is as expected at approximately 1,250 bbl/d net per well.
    - The 2019 drilling program of 3.9 net producer wells in the North Sea commenced in Q1/19 at the Ninian South Platform.

- Annual operating costs in the North Sea averaged $39.89/bbl (£23.06/bbl), within annual corporate guidance, as the Company continues to focus on production enhancements, increased reliability and water flood optimization.

- Offshore Africa production volumes in 2018 averaged 19,662 bbl/d, a decrease of 3% from 2017 levels, primarily as a result of natural field declines, partially offset by increased production in Q4/18 from a successful drilling program at Baobab.
  - Côte d'Ivoire crude oil operating costs in 2018 were $13.30/bbl (US$10.26/bbl), a 7% increase from 2017 mainly due to timing of liftings from Espoir and Baobab that have different cost structures, fluctuating production volumes on a relatively fixed cost base, planned maintenance activities and fluctuations in foreign exchange rates.
  - In 2018, the Company successfully drilled 1.7 net producer wells at Baobab. Current light crude oil production is exceeding sanctioned expectations at approximately 2,500 bbl/d net per well. As a result of the successful 2018 drilling program at Baobab, Canadian Natural targets to drill one additional producer well at Baobab in 2019.
  - In 2019, the Company targets to drill an appraisal well at Kossipo, and if successful will lead to development drilling and a pipeline tied-back to the Baobab Floating Production Storage and Offloading ("FPSO") vessel, adding significant future value with potential gross production capability of 20,000 bbl/d targeted in 2022.
  - At Espoir, the Company targets to commence the Phase 4 development in Q4/19 with initial production targeted for early 2020.
  - In Q4/18, the Gabonese Republic approved cessation of production from the Company’s Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic.
    - In late Q4/18, the Olowi field was shut in. Subsequent to year end, well suspensions were completed and the Olowi FPSO was off location in early Q1/19.
  - In Q4/18, the Company farmed out a further 5% working interest in the Exploration Right relating to Block 11B/12B located offshore South Africa. Canadian Natural's working interest in the Block is now 20%.
    - As a result of the farm out agreements, Canadian Natural received up front cash consideration and a financial carry on the exploration well costs and subsequent operations. Subject to there being a commercial discovery, the Company will receive further bonus payments.
    - Subsequent to year end, the operator of the South Africa exploration well announced a discovery of significant gas condensate and targets to evaluate further exploration wells on the Block. Canadian Natural expects the cost of the current exploration well to be fully carried. In 2019, the operator targets to acquire 3D seismic on the Block.

- The Company's 2019 International annual production guidance remains unchanged and is targeted to range from 42,000 bbl/d - 46,000 bbl/d.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Synthetic crude oil production (bbl/d) (1) (2)	**447,048**	394,382	321,496	**426,190**	282,026

(1) Q4/18 SCO production before royalties excludes 3,363 bbl/d of SCO consumed internally as diesel (Q3/18 – 2,758 bbl/d; Q4/17 – 1,730 bbl/d; 2018 – 3,093 bbl/d; 2017 – 651 bbl/d).

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

- At the Company's world class Oil Sands Mining and Upgrading assets, top tier operations provided record annual production of 426,190 bbl/d of SCO, an increase of 51% from 2017 levels. The increase in production was primarily due to a full year of Horizon Phase 3 operations and the acquisition of the AOSP in 2017.
  - The Company realized record low annual unadjusted operating costs of $21.75/bbl (US$16.78/bbl) of SCO in 2018, a decrease of 13% from 2017 levels. Operating costs were top tier, below the midpoint of guidance and were achieved through safe, steady and reliable operations, high utilization, and leveraging expertise to capture

synergies. After normalizing for planned turnaround downtime, operating costs decreased 10% to $21.05/bbl (US$16.24/bbl) of SCO compared to $23.40/bbl of SCO in 2017.

- The Company continues to progress engineering work on the previously announced potential expansion and reliability opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The engineering and design specification work is targeted to be complete in Q1/19. The remainder of the year will target to focus on key procurement and detailed engineering.
  - The potential Paraffinic Froth Treatment expansion at Horizon is targeting 40,000 bbl/d to 50,000 bbl/d of high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. The preliminary estimate of the capital required is approximately $1.4 billion.
  - Stage 1 and 2 reliability opportunities at Horizon are targeted to add near-term growth of 35,000 bbl/d to 45,000 bbl/d of SCO.
  - The Company targets to sanction the potential expansion and reliability opportunities with greater clarity on improved market access.
- As a result of Canadian Natural's continued focus on execution excellence and the Government of Alberta's mandated production curtailments, the Company has optimized planned maintenance timing within the Oil Sands Mining and Upgrading operations, as follows:
  - Canadian Natural has accelerated the timing of planned pit stop maintenance activities at Horizon to March 2019 from April 2019, optimizing production levels throughout the Company's assets. The planned maintenance is targeted for 12 days on the Vacuum Distillate and Diluent Recovery Unit furnaces at which time the Upgrader will run at restricted rates of approximately 140,000 bbl/d of SCO. Additional planned turnaround activities at Horizon are targeted for the fall of 2019.
  - The planned 38 day turnaround at the Scotford Upgrader is targeted for April and May 2019, at which time the Upgrader will run at restricted net rates of approximately 162,000 bbl/d of SCO. At AOSP, additional planned pit stop activities are targeted for the fall of 2019.
- The Company's 2019 Oil Sands Mining and Upgrading annual production guidance remains unchanged and is targeted to range between 415,000 bbl/d - 450,000 bbl/d of SCO.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 58.83**	$ 69.50	$ 55.39	**$ 64.78**	$ 50.93
WCS heavy differential as a percentage of WTI (%) [2]	**67%**	32%	22%	**41%**	23%
SCO price (US$/bbl)	**$ 37.48**	$ 68.44	$ 58.64	**$ 58.62**	$ 52.20
Condensate benchmark pricing (US$/bbl)	**$ 45.27**	$ 66.82	$ 57.96	**$ 60.98**	$ 51.65
Average realized pricing before risk management (C$/bbl) [3]	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.80**	$ 1.28	$ 1.85	**$ 1.45**	$ 2.30
Average realized pricing before risk management (C$/Mcf)	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76

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

- In Q4/18 there was a significant decline in crude oil pricing as a result of increased global supply, an oversupplied domestic market and a lack of takeaway capacity, resulting in increased storage levels in Q4/18, impacting pricing as follows:
  - WTI prices decreased 15% in Q4/18 from Q3/18 levels, reflecting increased global supply.

- The WCS heavy differential widened by 78% to US$39.36/bbl for Q4/18 from US$22.17/bbl for Q3/18. Following the Government of Alberta's announcement of a mandatory curtailment of crude oil production on December 2, 2018, the WCS differential index narrowed to US$12.38/bbl for Q1/19 from US$39.36/bbl for Q4/18.
- SCO prices in Q4/18 decreased 45% when compared to Q3/18 levels. Following the Government of Alberta's announcement of a mandatory curtailment of crude oil production on December 2, 2018, the differential between SCO and WTI benchmark pricing narrowed to US$2.70/bbl for Q1/19 from US$21.35/bbl for Q4/18.
- Condensate pricing in Q4/18 decreased when compared to Q4/17 and Q3/18 due to increased condensate supply, incremental blending of light crude oil into condensate and decreased demand due to curtailment of crude oil production in the basin.

▪ AECO natural gas prices increased in Q4/18 from Q3/18 and from Q2/18 levels reflecting the easing of third party pipeline constraints as well as seasonal demand factors. AECO natural gas prices decreased from 2017 levels, reflecting third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the basin.

▪ The North West Redwater ("NWR") refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by creating incremental demand for approximately 80,000 bbl/d of heavy crude oil blends that will not require export pipelines, helping to reduce pricing volatility in all Western Canadian heavy crude oil.
  - The 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

▪ Canadian Natural has invested over $3.1 billion in research and development since 2009 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 carbon capture facilities at its 50% interest through the NWR refinery. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year, making the Company the 3rd largest CO_2 capturer and sequester for the oil and gas sector globally once the NWR refinery is fully running.

▪ At Canadian Natural's Oil Sands Mining and Upgrading and thermal in situ operations, which represent approximately 65% of the Company's liquids production, the Company's emissions intensity is only approximately 5% higher than the average intensity for all global crude oils. By investing in and leveraging technology, including carbon capture initiatives, Canadian Natural has developed a pathway to reduce the Company's greenhouse gas emissions intensity to below the average for global crude oils.

▪ Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by its In Pit Extraction Process ("IPEP") pilot at Horizon, which will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's carbon emissions and environmental footprint by reducing the usage of haul trucks, the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to significantly reduce capital and operating costs.
  - 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. As a result of the positive results thus far, the Company continues to make enhancements and will operate and test the pilot through 2019.

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 1,078,813 BOE/d in 2018, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with current approximate product mix on a BOE/d basis of 52% light crude oil and SCO blends, 24% heavy crude oil blends and 24% natural gas, based upon annual 2018 production.
  - Canadian Natural's production is resilient, as long life low decline assets make up approximately 73% of 2018 annual liquids production, including the Oil Sands Mining and Upgrading, Pelican Lake and thermal in situ oil sands assets.
- In 2018, Canadian Natural delivered adjusted funds flow in excess of net capital expenditures of approximately $4,360 million, including deferred discounted purchase consideration. After dividend requirements, free cash flow totaled approximately $2,795 million in the year.
- Balance sheet strength and strong financial performance were demonstrated in 2018 through reduced long-term debt and upgraded credit ratings.
  - Canadian Natural settled the deferred AOSP acquisition liability totaling $481 million and reduced long-term debt by approximately $1,835 million, including the impact of foreign exchange, compared to 2017 levels.
  - In 2018, Moody's Investors Service, Inc. upgraded the Company's senior unsecured rating to Baa2 from Baa3 and its short term rating to P-2 from P-3 with a stable outlook. Additionally, Standard & Poor's revised the Company's rating outlook to BBB+/stable from BBB+/negative.
  - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At December 31, 2018 the Company had approximately $4,824 million of available liquidity, including cash and cash equivalents, an increase of approximately $574 million from 2017 levels.
  - As at December 31, 2018, debt to book capitalization improved to 39.1% from 41.4% in 2017 and debt to adjusted EBITDA strengthened to 2.0x from 2.7x in 2017.
- Returns to shareholders are a key focus for Canadian Natural as the Company returned a total of $2,844 million in the year, $1,562 million by way of dividends and $1,282 million by way of share purchases.
  - In the quarter, share purchases for cancellation totaled 10,845,000 common shares at a weighted average share price of $37.67.
  - In 2018, share purchases for cancellation totaled 30,857,727 common shares at a weighted average share price of $41.56.
  - Subsequent to year end and up to and including March 6, 2019, the Company executed on additional share purchases of 4,340,000 common shares for cancellation at a weighted average share price of $35.86.
- 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 new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, to share purchases under its NCIB and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. At present, this policy is expected to be in place until at least the Company's NCIB renewal in May 2019, subject to quarterly review by the Board of Directors. This policy was effective November 1, 2018.
- In addition to its strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at December 31, 2018, these financial levers include the Company's third party equity investments of approximately $524 million, and cross currency swaps and foreign currency forward contracts with a total value of $361 million.

- Subsequent to year end, Canadian Natural increased its quarterly dividend by 12% to $0.375 per share payable on April 1, 2019. The increase marks the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Director's confidence in Canadian Natural's sustainability and robustness of the asset base driving the ability to generate significant adjusted funds flow.

CORPORATE UPDATE

- The Board of Directors approved the previously announced leadership changes. The changes summarized below will be effective March 29, 2019.
  - Corey B. Bieber, Senior Vice-President Finance and Chief Financial Officer will become Executive Advisor.
  - Mark Stainthorpe, Vice President – Capital Markets, will assume the role of Chief Financial Officer and Senior Vice President, Finance and will join the Management Committee.
  - Ron Kim, Vice President, Finance – Corporate will assume the role of Principal Accounting Officer and Vice President, Finance, reporting to Mark Stainthorpe.

OUTLOOK

The Company targets annual 2019 production levels to average between 782,000 and 861,000 bbl/d of crude oil and NGLs and between 1,485 and 1,545 MMcf/d of natural gas, before royalties. Q1/19 production guidance before royalties is targeted to average between 759,000 and 817,000 bbl/d of crude oil and NGLs and between 1,490 and 1,520 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company’s website at www.cnrl.com.

Canadian Natural's annual 2019 capital expenditures are targeted to be approximately $3.7 billion.

2018 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2018, the Company retained Independent Qualified Reserves Evaluators (IQREs), Sproule Associates Limited, Sproule International Limited and GLJ Petroleum Consultants Limited, to evaluate and review all of the Company's proved and proved plus probable reserves. The IQREs conducted the evaluation and review in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves. All reserves values are Company Gross unless stated otherwise.

Corporate Total

- Canadian Natural's 2018 performance has resulted in another year of excellent finding and development costs:
  - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Capital ("FDC"), are $3.11/BOE for proved reserves and $2.31/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $9.39/BOE for proved reserves and $10.79/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 2018 production by 359%. Proved plus probable reserves additions and revisions replaced 2018 production by 485%.
- Proved reserves increased 12% to 9.893 billion BOE with reserves additions and revisions of 1.416 billion BOE. Proved plus probable reserves increased 13% to 13.382 billion BOE with reserves additions and revisions of 1.910 billion BOE.
- The proved BOE reserves life index is 27.7 years and the proved plus probable BOE reserves life index is 37.4 years.
- Proved developed producing reserves additions and revisions are 1.109 billion BOE, replacing 2018 production by 281%. The total proved developed producing BOE reserves life index is 21.3 years.
- Recycle ratios are 8.7 times and 11.8 times for proved and proved plus probable reserves respectively, excluding changes in FDC, recycle ratios are 2.9 times and 2.5 times for proved and proved plus probable reserves respectively, including changes in FDC.
- The net present value of future net revenues, before income tax, discounted at 10%, increased 19% to $106.6 billion for proved reserves and increased 14% to $131.0 billion for proved plus probable reserves. The net present value for proved developed producing reserves increased 24% to $84.2 billion reflecting the impact of the Horizon South Pit addition and decreased operating costs at AOSP.

North America Exploration and Production

- Canadian Natural's North America conventional and thermal assets delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $6.51/BOE for proved reserves and $3.50/BOE for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $7.23/BOE for proved reserves and $10.54/BOE for proved plus probable reserves.
- Proved reserves additions and revisions replaced 187% of 2018 production. Proved plus probable reserves additions and revisions replaced 349% of 2018 production.
- Proved reserves increased 6% to 3.588 billion BOE. This is comprised of 2.488 billion bbl of crude oil, bitumen, and NGL reserves and 6.597 Tcf of natural gas reserves.
- Proved plus probable reserves increased 10% to 6.027 billion BOE. This is comprised of 4.421 billion bbl of crude oil, bitumen, and NGL reserves and 9.633 Tcf of natural gas reserves.
- Proved reserves additions and revisions are 341 million bbl of crude oil, bitumen and NGL and 411 Bcf of natural gas. Proved plus probable reserves additions and revisions are 654 million bbl of crude oil, bitumen and NGL and 657 Bcf of natural gas.
- The proved BOE reserves life index is 18.9 years and the proved plus probable BOE reserves life index is 31.7 years.

North America Oil Sands Mining and Upgrading

- Canadian Natural's Oil Sands Mining and Upgrading segment delivered strong reserves results in 2018:
  - FD&A costs, excluding changes in FDC, are $1.47/bbl for proved reserves and $1.29/bbl for proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $10.49/bbl for proved reserves and $11.33/bbl for proved plus probable reserves.
- Proved SCO reserves increased 16% to 6.091 billion bbl. Proved plus probable SCO reserves increased 16% to 7.032 billion bbl.
- SCO reserves account for 62% of the Company's proved BOE reserves and 53% of the proved plus probable BOE reserves.

International Exploration and Production

- North Sea proved reserves are unchanged at 124 million BOE and proved plus probable reserves increased 4% to 193 million BOE.
- Offshore Africa proved reserves increased 5% to 90 million BOE and proved plus probable reserves decreased 4% to 131 million BOE.

2018 FD&A Costs excluding changes in FDC [10]	Proved ($/BOE)	Proved plus Probable ($/BOE)
North America E&P	$6.51	$3.50
Oil Sands Mining and Upgrading	$1.47	$1.29
Total Canadian Natural	$3.11	$2.31

2018 FD&A Costs including changes in FDC [11]	Proved ($/BOE)	Proved plus Probable ($/BOE)
North America E&P	$7.23	$10.54
Oil Sands Mining and Upgrading	$10.49	$11.33
Total Canadian Natural	$9.39	$10.79

Corporate Total

2018 Reserves Replacement [8]	% of 2018 Production Replaced
Proved Developed Producing	281%
Proved	359%
Proved plus Probable	485%

Company Gross Reserves	2017 (MMBOE)	2018 (MMBOE)	Increase
Proved Developed Producing	6,908	7,623	10%
Proved	8,871	9,893	12%
Proved plus Probable	11,866	13,382	13%

2018 Recycle Ratios [12]	Excluding changes in FDC	Including changes in FDC
Proved	8.7x	2.9x
Proved plus Probable	11.8x	2.5x

Net Present Value of Future Net Revenues, before income tax, discounted at 10% [13]	2017 ($ billion)	2018 ($ billion)	Increase
Proved Developed Producing	68.1	84.2	24%
Proved	89.8	106.6	19%
Proved plus Probable	114.5	131.0	14%

Summary of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	114	97	248	311	6,091	3,477	101	7,541
Developed Non-Producing	14	16	—	123	—	326	10	218
Undeveloped	66	69	57	1,106	—	2,794	156	1,920
Total Proved	194	182	305	1,540	6,091	6,597	267	9,679
Probable	74	70	140	1,519	941	3,036	130	3,379
Total Proved plus Probable	268	252	445	3,059	7,032	9,633	397	13,058
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	41					17		44
Developed Non-Producing	—					—		—
Undeveloped	45					11		46
Total Proved	86					28		90
Probable	35					35		41
Total Proved plus Probable	121					63		131
Total Company								
Proved								
Developed Producing	189	97	248	311	6,091	3,517	101	7,623
Developed Non-Producing	18	16	—	123	—	326	10	222
Undeveloped	192	69	57	1,106	—	2,809	156	2,048
Total Proved	399	182	305	1,540	6,091	6,652	267	9,893
Probable	176	70	140	1,519	941	3,082	130	3,489
Total Proved plus Probable	575	252	445	3,059	7,032	9,734	397	13,382

Summary of Company Net Reserves

As of December 31, 2018
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
North America								
Proved								
Developed Producing	101	81	189	252	5,125	3,183	80	6,358
Developed Non-Producing	12	14	—	104	—	303	8	189
Undeveloped	56	59	48	911	(8)	2,519	131	1,616
Total Proved	169	154	237	1,267	5,117	6,005	219	8,163
Probable	61	57	100	1,210	761	2,676	104	2,740
Total Proved plus Probable	230	211	337	2,477	5,878	8,681	323	10,903
North Sea								
Proved								
Developed Producing	34					23		38
Developed Non-Producing	4					—		4
Undeveloped	81					4		82
Total Proved	119					27		124
Probable	67					11		69
Total Proved plus Probable	186					38		193
Offshore Africa								
Proved								
Developed Producing	36					12		38
Developed Non-Producing	—					—		—
Undeveloped	36					9		38
Total Proved	72					21		76
Probable	26					23		30
Total Proved plus Probable	98					44		106
Total Company								
Proved								
Developed Producing	171	81	189	252	5,125	3,218	80	6,434
Developed Non-Producing	16	14	—	104	—	303	8	193
Undeveloped	173	59	48	911	(8)	2,532	131	1,736
Total Proved	360	154	237	1,267	5,117	6,053	219	8,363
Probable	154	57	100	1,210	761	2,710	104	2,839
Total Proved plus Probable	514	211	337	2,477	5,878	8,763	323	11,202

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROVED

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	171	198	327	1,350	5,264	6,730	229	8,661
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	17	6	—	4	—	470	38	143
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	3	2	—	—	—	82	4	22
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	—	1	1	—	—	(305)	(4)	(53)
Technical Revisions	10	(2)	(1)	52	175	42	6	247
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**194**	**182**	**305**	**1,540**	**6,091**	**6,597**	**267**	**9,679**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	120	21	124
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	1	—	1
Improved Recovery	—	—	—
Acquisitions	8	—	8
Dispositions	—	—	—
Economic Factors	5	—	5
Technical Revisions	(6)	18	(3)
Production	(9)	(12)	(11)
December 31, 2018	**119**	**27**	**124**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	83	20	86
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	10	17	13
Production	(7)	(9)	(9)
December 31, 2018	**86**	**28**	**90**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	374	198	327	1,350	5,264	6,771	229	8,871
Discoveries	—	—	—	—	—	—	—	—
Extensions	12	14	—	171	808	122	9	1,034
Infill Drilling	18	6	—	4	—	470	38	144
Improved Recovery	—	—	1	2	—	3	—	4
Acquisitions	11	2	—	—	—	82	4	30
Dispositions	—	(5)	—	—	—	(3)	—	(5)
Economic Factors	5	1	1	—	—	(305)	(4)	(48)
Technical Revisions	14	(2)	(1)	52	175	77	6	257
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**399**	**182**	**305**	**1,540**	**6,091**	**6,652**	**267**	**9,893**

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	68	74	142	1,230	799	2,790	106	2,884
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	1	1	—	403	—	22	1	410
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(1)	—	—	—	—	(104)	(1)	(19)
Technical Revisions	(5)	(13)	(4)	(176)	71	(155)	(3)	(157)
Production	—	—	—	—	—	—	—	—
December 31, 2018	**74**	**70**	**140**	**1,519**	**941**	**3,036**	**130**	**3,379**

North Sea	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	60					11		61
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	5					—		5
Dispositions	—					—		—
Economic Factors	(5)					—		(5)
Technical Revisions	7					—		8
Production	—					—		—
December 31, 2018	**67**					**11**		**69**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	42					47		50
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	(7)					(12)		(9)
Production	—					—		—
December 31, 2018	**35**					**35**		**41**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	170	74	142	1,230	799	2,848	106	2,995
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	7	—	59	71	93	5	162
Infill Drilling	6	2	—	1	—	391	22	97
Improved Recovery	1	—	2	2	—	1	—	4
Acquisitions	6	1	—	403	—	22	1	415
Dispositions	—	(1)	—	—	—	(2)	—	(2)
Economic Factors	(6)	—	—	—	—	(104)	(1)	(24)
Technical Revisions	(5)	(13)	(4)	(176)	71	(167)	(3)	(158)
Production	—	—	—	—	—	—	—	—
December 31, 2018	**176**	**70**	**140**	**1,519**	**941**	**3,082**	**130**	**3,489**

Reconciliation of Company Gross Reserves

As of December 31, 2018
Forecast Prices and Costs

PROVED PLUS PROBABLE

North America	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	239	272	469	2,580	6,063	9,520	335	11,545
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	23	8	—	5	—	861	60	240
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	4	3	—	403	—	104	5	432
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	5	(15)	(5)	(124)	246	(113)	3	90
Production	(19)	(32)	(23)	(39)	(156)	(544)	(15)	(374)
December 31, 2018	**268**	**252**	**445**	**3,059**	**7,032**	**9,633**	**397**	**13,058**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	180	32	185
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	1	—	1
Improved Recovery	—	—	—
Acquisitions	13	—	13
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	1	18	5
Production	(9)	(12)	(11)
December 31, 2018	**186**	**38**	**193**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	125	67	136
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	3	5	4
Production	(7)	(9)	(9)
December 31, 2018	**121**	**63**	**131**

Total Company	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
December 31, 2017	544	272	469	2,580	6,063	9,619	335	11,866
Discoveries	—	—	—	—	—	—	—	—
Extensions	16	21	—	230	879	215	14	1,196
Infill Drilling	24	8	—	5	—	861	60	241
Improved Recovery	1	—	3	4	—	4	—	8
Acquisitions	17	3	—	403	—	104	5	445
Dispositions	—	(6)	—	—	—	(5)	—	(7)
Economic Factors	(1)	1	1	—	—	(409)	(5)	(72)
Technical Revisions	9	(15)	(5)	(124)	246	(90)	3	99
Production	(35)	(32)	(23)	(39)	(156)	(565)	(15)	(394)
December 31, 2018	**575**	**252**	**445**	**3,059**	**7,032**	**9,734**	**397**	**13,382**

Reserves Notes:

(1) *Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.*

(2) *Company Net reserves are working interest share after deduction of royalties and including any royalty interests.*

(3) *BOE values may not calculate due to rounding.*

(4) *Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates were provided by Sproule Associates Limited:*

	2019	2020	2021	2022	2023	Average annual increase thereafter
Crude oil and NGL						
WTI at Cushing (US$/bbl)	$ 63.00	$ 67.00	$ 70.00	$ 71.40	$ 72.83	2.00%
Western Canada Select (C$/bbl)	$ 59.47	$ 62.31	$ 67.45	$ 69.53	$ 71.66	2.00%
Canadian Light Sweet (C$/bbl)	$ 75.27	$ 77.89	$ 82.25	$ 84.79	$ 87.39	2.00%
Cromer LSB (C$/bbl)	$ 75.27	$ 76.89	$ 81.25	$ 83.79	$ 86.39	2.00%
Edmonton Pentanes+ (C$/bbl)	$ 75.32	$ 80.00	$ 83.75	$ 85.50	$ 87.29	2.00%
North Sea Brent (US$/bbl)	$ 70.00	$ 72.00	$ 73.00	$ 74.46	$ 75.95	2.00%
Natural gas						
AECO (C$/MMBtu)	$ 1.95	$ 2.44	$ 3.00	$ 3.21	$ 3.30	2.00%
BC Westcoast Station 2 (C$/MMBtu)	$ 1.35	$ 1.94	$ 2.60	$ 2.81	$ 2.90	2.00%
Henry Hub (US$/MMBtu)	$ 3.00	$ 3.25	$ 3.50	$ 3.57	$ 3.64	2.00%

Note: A foreign exchange rate of 0.7700 US$/C$ for 2019 and 0.8000 US$/C$ after 2019 was used in the 2018 evaluation.

(5) *A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel 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.*

(6) *Metrics included herein are commonly used in the oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.*

(7) *Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.*

(8) *Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.*

(9) *Reserves Life Index is based on the amount for the relevant reserves category divided by the 2019 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.*

(10) *Finding, Development and Acquisition ("FD&A") costs are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 by the sum of total additions and revisions for the relevant reserves category. All values used in the calculation are not rounded.*

(11) *FD&A costs including changes in Future Development Capital ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2018 and net changes in FDC from December 31, 2017 to December 31, 2018 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment and reclamation costs. All values used in the calculation are not rounded.*

(12) *Recycle Ratio is the operating netback ($27.13/BOE for 2018) divided by the FD&A (in $/BOE). Operating netback is production revenues, excluding realized gains and losses on commodity hedging, less royalties, transportation and production expenses, calculated on a per BOE basis.*

(13) *Abandonment and reclamation costs included in the calculation of the Future Net Revenue (FNR) for 2018 consist of both forecast estimates of abandonment and reclamation costs attributable to future development activity, as well as certain costs already included in the Company's Asset Retirement Obligation (ARO) for development existing as at December 31, 2018. The portion of the Company's estimated ARO included in the reserves FNR is escalated at 2.0% per year after 2019. Specifically, for North America (excluding SCO assets), FNR includes the ARO costs associated with abandonment and reclamation of wells (wells, well sites, well site equipment and pipelines) with assigned reserves. For SCO assets, FNR includes the ARO costs associated with the abandonment and reclamation of the mine site and all mining facilities and for Horizon assets, it also includes abandonment and reclamation of the upgrading facilities. For North Sea and Offshore Africa, FNR includes the ARO costs associated with the abandonment and reclamation of offshore wells and facilities with assigned reserves.*

ADVISORY

Special Note Regarding non-GAAP and other Financial Measures

This interim report includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; free cash flow; debt to adjusted EBITDA; available liquidity; finding, development and acquisition ("FD&A") costs; recycle ratio; reserves life index; production replacement ratio; adjusted operating costs; and unadjusted operating costs. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures and other financial measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, cash flows used in investing activities, and cash flows used in financing 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 the Company's 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 and certain movements in other long-term assets. 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.

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 9 - Long-term Debt in the Company's consolidated financial statements.

Finding, Development and Acquisition ("FD&A") costs is a non-GAAP measure that is derived by dividing the sum of total net capital expenditures excluding midstream, abandonments, and head office, by the sum of total additions and revisions for the relevant reserves category. The Company considers FD&A costs a key measure in evaluating the Company's performance, as it provides the reader with an understanding of the Company's ability to effectively find and develop reserves and make opportunistic acquisitions that add to the Company's reserves base.

Recycle Ratio is a non-GAAP measure that is derived by dividing the operating netback by the FD&A cost for the relevant category. Operating netback for a segment or product is derived as product sales net of blending costs, less royalties, transportation and production expenses, calculated on a per BOE basis. The Company considers recycle ratio a key measure in evaluating the Company's ability to generate profitability on its capital investment.

Reserves life index is based on the total reserves amount for the relevant category divided by the 2019 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.

Production replacement ratio is derived as the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.

Adjusted operating costs are derived as production expense based on sales volumes excluding costs incurred in turnaround periods. See "Operating Highlights - Oil Sands Mining and Upgrading" section in the Company's MD&A.

Unadjusted operating costs also referred to as cash production costs in the Company's MD&A. See "Operating Highlights - Oil Sands Mining and Upgrading" section in the Company's MD&A.

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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 cost and timing of construction and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new or expansion of existing pipeline capacity or other means of transportation of bitumen, crude oil, natural gas or synthetic crude oil (“SCO”) that the Company may be reliant upon to transport its products to market, development and deployment of technology and technological innovations and the assumption of operations at processing facilities also constitute forward-looking statements. 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 natural gas liquids (“NGLs”) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from 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; 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, 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 (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations); net capital expenditures; adjusted cash production costs and adjusted depreciation, depletion and amortization. These financial measures are not defined by 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 (loss), 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 (loss) from operations is reconciled to net earnings (loss), 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 derivation of adjusted cash production costs and adjusted depreciation, depletion and amortization are included in the "Operating Highlights - Oil Sands Mining and Upgrading" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

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 months and year ended December 31, 2018 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2017. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three months and year ended December 31, 2018 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this MD&A on a "before royalty" 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 royalty" or "net" basis is also presented for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2018 in relation to the comparable periods in 2017 and the third quarter of 2018. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2017, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com. This MD&A is dated March 6, 2019.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
Product sales	**$ 3,831**	$ 6,327	$ 5,516	**$ 22,282**	$ 18,360
Crude oil and NGLs	**$ 3,327**	$ 5,967	$ 5,098	**$ 20,668**	$ 16,522
Natural gas	**$ 504**	$ 360	$ 418	**$ 1,614**	$ 1,838
Net earnings (loss)	**$ (776)**	$ 1,802	$ 396	**$ 2,591**	$ 2,397
Per common share – basic	**$ (0.64)**	$ 1.48	$ 0.32	**$ 2.13**	$ 2.04
– diluted	**$ (0.64)**	$ 1.47	$ 0.32	**$ 2.12**	$ 2.03
Adjusted net earnings (loss) from operations (1)	**$ (255)**	$ 1,354	$ 565	**$ 3,263**	$ 1,403
Per common share – basic	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.68**	$ 1.19
– diluted	**$ (0.21)**	$ 1.11	$ 0.46	**$ 2.67**	$ 1.19
Cash flows from operating activities	**$ 1,397**	$ 3,642	$ 1,438	**$ 10,121**	$ 7,262
Adjusted funds flow (2)	**$ 1,229**	$ 2,830	$ 2,307	**$ 9,088**	$ 7,347
Per common share – basic	**$ 1.02**	$ 2.32	$ 1.89	**$ 7.46**	$ 6.25
– diluted	**$ 1.02**	$ 2.31	$ 1.88	**$ 7.43**	$ 6.21
Cash flows used in investing activities	**$ 1,042**	$ 1,265	$ 1,074	**$ 4,814**	$ 13,102
Net capital expenditures (3)	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for 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 the Company's 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 this MD&A. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

(2) Adjusted funds flow (previously referred to as funds flow from operations) is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment and certain movements in other long-term assets. 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 this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

(3) Net capital expenditures is a non-GAAP measure that represents cash flows 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 this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

Adjusted Net Earnings (Loss) from Operations, as Reconciled to Net Earnings (Loss)

($ millions)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Net earnings (loss)	**$ (776)**	$ 1,802	$ 396	**$ 2,591**	$ 2,397
Share-based compensation, net of tax (1)	**(148)**	(85)	97	**(146)**	134
Unrealized risk management loss (gain), net of tax (2)	**17**	(11)	68	**(36)**	33
Unrealized foreign exchange loss (gain), net of tax (3)	**548**	(182)	(2)	**706**	(821)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	—	—	**146**	—
Loss (gain) from investments, net of tax (5) (6)	**134**	89	(4)	**374**	(11)
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	**(30)**	(259)	—	**(372)**	(339)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	—	10	**—**	10
Adjusted net earnings (loss) from operations	**$ (255)**	$ 1,354	$ 565	**$ 3,263**	$ 1,403

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

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

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

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

(7) During the fourth quarter of 2018, the Company recorded a pre-tax gain of $16 million ($12 million after-tax) on the disposition of a 30% interest in the exploration right in South Africa. Additionally, during the fourth quarter of 2018, the Gabonese Republic approved cessation of production from the Company's Olowi field and associated asset retirement obligations, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, resulting in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). 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. During the third quarter of 2017, the Company recorded a pre-tax revaluation gain of $114 million ($83 million after-tax) related to a previously held joint interest in a pipeline system. During the second quarter of 2017, the Company recorded a pre and after-tax gain of $230 million on the acquisition of a direct and indirect 70% interest in AOSP and other assets from Shell Canada Limited and certain subsidiaries ("Shell") and an affiliate of Marathon Oil Corporation ("Marathon"), and a pre-tax gain of $35 million ($26 million after-tax) on the disposition of certain exploration and evaluation assets in the North America segment.

(8) During the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million.

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

($ millions)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Cash flows from operating activities	**$ 1,397**	$ 3,642	$ 1,438	**$ 10,121**	$ 7,262
Net change in non-cash working capital	**(279)**	(889)	709	**(1,346)**	(299)
Abandonment expenditures (2)	**93**	57	63	**290**	274
Other (3)	**18**	20	97	**23**	110
Adjusted funds flow	**$ 1,229**	$ 2,830	$ 2,307	**$ 9,088**	$ 7,347

(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) Includes certain movements in other long-term assets.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings (Loss) and Adjusted Net Earnings (Loss)

Net earnings for the year ended December 31, 2018 were $2,591 million compared with net earnings of $2,397 million for the year ended December 31, 2017. Net earnings for the year ended December 31, 2018 included net after-tax expenses of $672 million compared with net after-tax income of $994 million for the year ended December 31, 2017 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss (gain) from investments, gain on acquisition, disposition 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 year ended December 31, 2018 were $3,263 million compared with adjusted net earnings from operations of $1,403 million for the year ended December 31, 2017.

The net loss for the fourth quarter of 2018 was $776 million compared with net earnings of $396 million for the fourth quarter of 2017 and net earnings of $1,802 million for the third quarter of 2018. The net loss for the fourth quarter of 2018 included net after-tax expenses of $521 million compared with net after-tax expenses of $169 million for the fourth quarter of 2017 and net after-tax income of $448 million for the third quarter of 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) from investments, gain on acquisition, disposition and revaluation of properties, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the fourth quarter of 2018 was $255 million compared with adjusted net earnings from operations of $565 million for the fourth quarter of 2017 and adjusted net earnings of $1,354 million for the third quarter of 2018.

The increase in net earnings and adjusted net earnings from operations for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to:

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

partially offset by:

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

The net loss and adjusted net loss from operations for the fourth quarter of 2018 as compared to net earnings and adjusted net earnings from operations in the fourth quarter of 2017 and the third quarter of 2018 was primarily due to a significant decline in crude oil pricing in November and December 2018 as a result of an oversupplied domestic market environment and a lack of takeaway capacity, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The Western Canadian Select ("WCS") heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$22.17 per bbl, fourth quarter of 2017 - US$12.28 per bbl). The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018 (third quarter of 2018 - US$68.44 per bbl, fourth quarter of 2017 - US$58.64 per bbl).

Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019 and the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019. Crude oil and natural gas pricing are discussed in detail in the "Business Environment" section of this MD&A.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings (loss) for the three months and year ended December 31, 2018 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 year ended December 31, 2018 were $10,121 million compared with $7,262 million for the year ended December 31, 2017. Cash flows from operating activities for the fourth quarter of 2018 were $1,397 million compared with $1,438 million for the fourth quarter of 2017 and $3,642 million for the third quarter of 2018. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2018 were $9,088 million compared with $7,347 million for the year ended December 31, 2017. Adjusted funds flow for the fourth quarter of 2018 were $1,229 million compared with $2,307 million for the fourth quarter of 2017 and $2,830 million for the third quarter of 2018. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment and certain movements in other long-term assets.

Production Volumes

Total production before royalties for the fourth quarter of 2018 increased 6% to 1,081,368 BOE/d from 1,020,094 BOE/d for the fourth quarter of 2017 and increased 2% from 1,060,629 BOE/d for the third quarter of 2018. 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)	**Dec 31 2018**	Sep 30 2018	Jun 30 2018	Mar 31 2018
Product sales	**$ 3,831**	$ 6,327	$ 6,389	$ 5,735
Crude oil and NGLs	**$ 3,327**	$ 5,967	$ 6,071	$ 5,303
Natural gas	**$ 504**	$ 360	$ 318	$ 432
Net earnings (loss)	**$ (776)**	$ 1,802	$ 982	$ 583
Net earnings (loss) per common share				
– basic	**$ (0.64)**	$ 1.48	$ 0.80	$ 0.48
– diluted	**$ (0.64)**	$ 1.47	$ 0.80	$ 0.47
($ millions, except per common share amounts)	Dec 31 2017	Sep 30 2017	Jun 30 2017	Mar 31 2017
Product sales	$ 5,516	$ 4,725	$ 4,127	$ 3,992
Crude oil and NGLs	$ 5,098	$ 4,320	$ 3,645	$ 3,459
Natural gas	$ 418	$ 405	$ 482	$ 533
Net earnings (loss)	$ 396	$ 684	$ 1,072	$ 245
Net earnings (loss) per common share				
– basic	$ 0.32	$ 0.56	$ 0.93	$ 0.22
– diluted	$ 0.32	$ 0.56	$ 0.93	$ 0.22

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 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") and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and 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, fluctuations in the Company's drilling program in North America, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, 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 due to low commodity prices in North America, and the impact of the drilling program in the International segments. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at a third-party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production 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, including the acquisition of AOSP and other assets, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark - to - market and subsequent settlement of the Company's risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense 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 gains on the acquisition of AOSP and other assets, the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

(Average for the period)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
WTI benchmark price (US$/bbl)	**$ 58.83**	$ 69.50	$ 55.39	**$ 64.78**	$ 50.93
Dated Brent benchmark price (US$/bbl)	**$ 67.45**	$ 75.46	$ 61.46	**$ 71.12**	$ 54.38
WCS heavy differential from WTI (US$/bbl)	**$ 39.36**	$ 22.17	$ 12.28	**$ 26.29**	$ 11.97
SCO price (US$/bbl)	**$ 37.48**	$ 68.44	$ 58.64	**$ 58.62**	$ 52.20
Condensate benchmark price (US$/bbl)	**$ 45.27**	$ 66.82	$ 57.96	**$ 60.98**	$ 51.65
NYMEX benchmark price (US$/MMBtu)	**$ 3.65**	$ 2.90	$ 2.94	**$ 3.08**	$ 3.11
AECO benchmark price (C$/GJ)	**$ 1.80**	$ 1.28	$ 1.85	**$ 1.45**	$ 2.30
US/Canadian dollar average exchange rate (US$)	**$ 0.7573**	$ 0.7651	$ 0.7865	**$ 0.7717**	$ 0.7701

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$64.78 per bbl for the year ended December 31, 2018, an increase of 27% from US$50.93 per bbl for the year ended December 31, 2017. WTI averaged US$58.83 per bbl for the fourth quarter of 2018, an increase of 6% from US$55.39 per bbl for the fourth quarter of 2017, and a decrease of 15% from US$69.50 per bbl for the third quarter of 2018.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$71.12 per bbl for the year ended December 31, 2018, an increase of 31% from US$54.38 per bbl for the year ended December 31, 2017. Brent averaged US$67.45 per bbl for the fourth quarter of 2018, an increase of 10% from US$61.46 per bbl for the fourth quarter of 2017, and a decrease of 11% from US$75.46 per bbl for the third quarter of 2018.

WTI and Brent pricing for the three months and year ended December 31, 2018 has increased from the comparable periods in 2017 primarily due to declines in global crude oil inventories, together with larger than anticipated increases in global demand for crude oil. The decrease in WTI and Brent pricing for the fourth quarter of 2018 as compared with the third quarter of 2018 reflected increased global supply with increases in the US and Saudi Arabia, and notwithstanding OPEC's previously announced production cuts.

The WCS heavy differential averaged US$26.29 per bbl for the year ended December 31, 2018, an increase of 120% from US$11.97 per bbl for the year ended December 31, 2017. The WCS heavy differential averaged US$39.36 per bbl for the fourth quarter of 2018, an increase of 221% from US$12.28 per bbl for the fourth quarter of 2017, and an increase of 78% from US$22.17 per bbl for the third quarter of 2018. The significant widening of the WCS heavy differential for the three months and year ended December 31, 2018 from the comparable periods reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system in the fourth quarter of 2018. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the WCS heavy differential index narrowed to US$12.38 per bbl for the first quarter of 2019.

The SCO price averaged US$58.62 per bbl for the year ended December 31, 2018, an increase of 12% from US$52.20 per bbl for the year ended December 31, 2017. The SCO price averaged US$37.48 per bbl for the fourth quarter of 2018, a decrease of 36% from US$58.64 per bbl for the fourth quarter of 2017, and a decrease of 45% from US$68.44 per bbl for the third quarter of 2018. The increase in SCO pricing for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected increases in WTI benchmark pricing through the third quarter of 2018, partially offset by decreased pricing in the fourth quarter of 2018 due to a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. Following the Government of Alberta's announcement on December 2, 2018 of a mandatory curtailment of crude oil production, the differential between SCO and WTI benchmark pricing narrowed to US$2.70 per bbl for the first quarter of 2019.

Condensate pricing averaged US$60.98 per bbl for the year ended December 31, 2018, an increase of 18% from US$51.65 per bbl for the year ended December 31, 2017. Condensate pricing averaged US$45.27 per bbl for the fourth quarter of 2018, a decrease of 22% from US$57.96 per bbl for the fourth quarter of 2017, and a decrease of 32% from US$66.82 per bbl for the third quarter of 2018. Condensate pricing for the year ended December 31, 2018 increased from the year ended December 31, 2017 due to increasing underlying benchmark pricing. The decrease in condensate pricing for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected the impact of increased condensate supply, incremental blending of light crude oil into condensate and decreased demand due to curtailment of heavy oil production in the Basin.

NYMEX natural gas prices averaged US$3.08 per MMBtu for the year ended December 31, 2018, comparable with US$3.11 per MMBtu for the year ended December 31, 2017. NYMEX natural gas prices averaged US$3.65 per MMBtu for the fourth quarter of 2018, an increase of 24% from US$2.94 per MMBtu for the fourth quarter of 2017, and an increase of 26% from US$2.90 per MMBtu for the third quarter of 2018. The increase in NYMEX natural gas prices for the fourth quarter of 2018 compared with the fourth quarter of 2017 and third quarter of 2018 primarily reflected low storage inventory levels in North America and seasonal demand factors.

AECO natural gas prices averaged $1.45 per GJ for the year ended December 31, 2018, a decrease of 37% from $2.30 per GJ for the year ended December 31, 2017. AECO natural gas prices averaged $1.80 per GJ for the fourth quarter of 2018, a decrease of 3% from $1.85 per GJ for the fourth quarter of 2017, and an increase of 41% from $1.28 per GJ for the third quarter of 2018. The decrease in AECO natural gas prices for the three months and year ended December 31, 2018 from the comparable periods in 2017 reflected third party pipeline constraints limiting flow of natural gas to export markets as well as increased natural gas production in the Basin. The increase in AECO natural gas prices for the fourth quarter of 2018 compared with the third quarter of 2018 reflected the easing of third party pipeline constraints as well as seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**343,054**	359,856	383,537	**350,961**	359,449
North America – Oil Sands Mining and Upgrading [(1)]	**447,048**	394,382	321,496	**426,190**	282,026
North Sea	**21,071**	28,702	19,548	**23,965**	23,426
Offshore Africa	**22,185**	18,802	19,519	**19,662**	20,335
	833,358	801,742	744,100	**820,778**	685,236
Natural gas (MMcf/d)					
North America	**1,441**	1,489	1,596	**1,490**	1,601
North Sea	**22**	38	37	**32**	39
Offshore Africa	**25**	26	23	**26**	22
	1,488	1,553	1,656	**1,548**	1,662
Total barrels of oil equivalent (BOE/d)	**1,081,368**	1,060,629	1,020,094	**1,078,813**	962,264
Product mix					
Light and medium crude oil and NGLs	**13%**	13%	13%	**13%**	14%
Pelican Lake heavy crude oil	**6%**	6%	6%	**6%**	6%
Primary heavy crude oil	**7%**	9%	10%	**8%**	10%
Bitumen (thermal oil)	**10%**	11%	12%	**10%**	12%
Synthetic crude oil	**41%**	37%	32%	**39%**	29%
Natural gas	**23%**	24%	27%	**24%**	29%
Percentage of gross revenue [(1) (2)] (excluding Midstream revenue)					
Crude oil and NGLs	**85%**	95%	92%	**93%**	90%
Natural gas	**15%**	5%	8%	**7%**	10%

(1) Fourth quarter 2018 SCO production before royalties excludes 3,363 bbl/d of SCO consumed internally as diesel (third quarter 2018 – 2,758 bbl/d; fourth quarter 2017 – 1,730 bbl/d; year ended December 31, 2018 – 3,093 bbl/d; year ended December 31, 2017 – 651 bbl/d).

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**304,324**	307,668	333,698	**303,956**	312,297
North America – Oil Sands Mining and Upgrading	**421,421**	372,521	309,777	**405,731**	274,437
North Sea	**21,021**	28,609	19,518	**23,902**	23,382
Offshore Africa	**21,366**	17,264	17,885	**18,450**	19,124
	768,132	726,062	680,878	**752,039**	629,240
Natural gas (MMcf/d)					
North America	**1,396**	1,455	1,538	**1,432**	1,528
North Sea	**22**	38	37	**32**	39
Offshore Africa	**22**	22	20	**23**	20
	1,440	1,515	1,595	**1,487**	1,587
Total barrels of oil equivalent (BOE/d)	**1,008,210**	978,481	946,731	**999,857**	893,702

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

Crude oil and NGLs production for the year ended December 31, 2018 increased 20% to 820,778 bbl/d from 685,236 bbl/d for the year ended December 31, 2017. Crude oil and NGLs production for the fourth quarter of 2018 of 833,358 bbl/d increased 12% from 744,100 bbl/d for the fourth quarter of 2017, and increased 4% from 801,742 bbl/d in the third quarter of 2018. The increase in crude oil and NGLs production for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of Phase 3 production at Horizon and acquisitions completed in 2017, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling. The increase in crude oil and NGLs production for the fourth quarter of 2018 compared to the fourth quarter of 2017 and the third quarter of 2018 reflected strong production in the Oil Sands Mining and Upgrading segment, partially offset by the impact of proactive measures taken by the Company to voluntarily curtail crude oil production and reduce heavy oil drilling.

Annual 2018 crude oil and NGLs production was above the midpoint of the Company's previously issued guidance of 812,000 to 822,000 bbl/d. First quarter 2019 crude oil and NGLs production guidance is targeted to average between 759,000 and 817,000 bbl/d. Annual crude oil and NGLs production guidance for 2019 is targeted to average between 782,000 and 861,000 bbl/d. Crude oil and NGLs production guidance for 2019 reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Natural gas production for the year ended December 31, 2018 decreased 7% to 1,548 MMcf/d from 1,662 MMcf/d for the year ended December 31, 2017. Natural gas production for the fourth quarter of 2018 averaged 1,488 MMcf/d, a decrease of 10% from 1,656 MMcf/d for the fourth quarter of 2017, and a decrease of 4% from 1,553 MMcf/d for the third quarter of 2018. The decrease in natural gas production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with downtime and restricted capacity at the third-party Pine River processing facility. Production in the fourth quarter of 2018 also reflected the impact of reduced pipeline capacity due to a failure on a natural gas transmission line in British Columbia (T-South) in October 2018. Subject to regulatory approval, the Company targets to take over operations at the processing facility in the first half of 2019.

Annual 2018 natural gas production was within the Company's previously issued guidance of 1,545 to 1,555 MMcf/d. First quarter 2019 natural gas production guidance is targeted to average between 1,490 and 1,520 MMcf/d. Annual natural gas production guidance for 2019 is targeted to average between 1,485 and 1,545 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the year ended December 31, 2018 averaged 350,961 bbl/d, a decrease of 2% from 359,449 bbl/d for the year ended December 31, 2017. North America crude oil and NGLs production for the fourth quarter of 2018 of 343,054 bbl/d decreased 11% from 383,537 bbl/d for the fourth quarter of 2017, and decreased 5% from 359,856 bbl/d for the third quarter of 2018. The decrease in production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of proactive measures taken by the Company to voluntarily curtail crude oil production, together with reduced heavy oil drilling and natural field declines.

Operating performance at Pelican Lake continued to be strong, leading to production of 62,428 bbl/d in the fourth quarter of 2018 compared with 65,654 bbl/d in the fourth quarter of 2017 and 62,727 bbl/d in the third quarter of 2018. The decrease in production from the fourth quarter of 2017 reflected the impact of the Company restoring polymer flood on the acquired Pelican assets to 62% of the field during 2018. Production in the third and fourth quarters of 2018 has been relatively stable.

Overall thermal oil production for the fourth quarter of 2018 averaged 102,112 bbl/d compared with 124,121 bbl/d for the fourth quarter of 2017 and 112,542 bbl/d for the third quarter of 2018. Annual 2018 thermal oil production of 107,839 bbl/d was at the high end of the Company's previously issued guidance of 106,000 to 108,000 bbl/d. First quarter 2019 thermal oil production guidance is targeted to average between 92,000 and 98,000 bbl/d. Annual thermal oil production guidance for 2019 is targeted to average between 104,000 and 124,000 bbl/d. Thermal oil production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Annual 2018 crude oil and NGLs production, including thermal oil, was above the Company's previously issued guidance of 346,000 to 350,000 bbl/d. First quarter 2019 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 313,000 and 327,000 bbl/d. Annual crude oil and NGLs production guidance for 2019, including thermal oil, is targeted to average between 325,000 and 365,000 bbl/d. Crude oil production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019.

Natural gas production for the year ended December 31, 2018 decreased 7% to 1,490 MMcf/d from 1,601 MMcf/d for the year ended December 31, 2017. Natural gas production for the fourth quarter of 2018 averaged 1,441 MMcf/d, a decrease of 10% from 1,596 MMcf/d for the fourth quarter of 2017, and a decrease of 3% from 1,489 MMcf/d in the third quarter of 2018. The decrease in production for the three months and year ended December 31, 2018 from the comparable periods primarily reflected the impact of shut-in volumes due to low natural gas prices, natural field declines and reduced drilling activity, together with downtime and restricted capacity at the third-party Pine River processing facility. Production in the fourth quarter of 2018 also reflected the impact of reduced pipeline capacity due to a failure on a natural gas transmission line in British Columbia (T-South) in October 2018.

North America – Oil Sands Mining and Upgrading

SCO production for the year ended December 31, 2018 of 426,190 bbl/d increased 51% from 282,026 bbl/d for the year ended December 31, 2017. SCO production for the fourth quarter of 2018 increased 39% to average 447,048 bbl/d from 321,496 bbl/d for the fourth quarter of 2017 and increased 13% from 394,382 bbl/d for the third quarter of 2018. The increase in SCO production for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected the impact of Phase 3 production at Horizon and the acquisition of AOSP. The increase in the fourth quarter of 2018 from the fourth quarter of 2017 primarily reflected one full quarter of production at Horizon Phase 3. The increase in the fourth quarter of 2018 from the third quarter of 2018 reflected strong production and effective and efficient operations at Horizon following the successful completion of the planned turnaround in the third quarter of 2018.

Annual 2018 SCO production was within the Company's previously issued guidance of 424,000 to 428,000 bbl/d. First quarter 2019 SCO production guidance is targeted to average between 400,000 and 440,000 bbl/d. Annual SCO production guidance for 2019 is targeted to average between 415,000 and 450,000 bbl/d. SCO production guidance reflects production curtailments as currently mandated by the Government of Alberta for the first quarter of 2019 and the moving forward of planned maintenance activities at Horizon from April 2019 to March 2019.

North Sea

North Sea crude oil production for the year ended December 31, 2018 of 23,965 bbl/d increased 2% from 23,426 bbl/d for the year ended December 31, 2017. North Sea crude oil production for the fourth quarter of 2018 increased 8% to 21,071 bbl/d from 19,548 bbl/d for the fourth quarter of 2017 and decreased 27% from 28,702 bbl/d in the third quarter of 2018. The increase in production for the three months and year ended December 31, 2018 from the comparable periods in 2017 primarily reflected the successful drilling program completed in 2018, offsetting planned maintenance at the Ninian Central and Tiffany platforms as well as on the Banff FPSO during the fourth quarter of 2018 together with natural field declines. The decrease in production for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the planned turnarounds and maintenance activities completed during the fourth quarter as well as natural field declines.

Offshore Africa

Offshore Africa crude oil production for the year ended December 31, 2018 decreased 3% to 19,662 bbl/d from 20,335 bbl/d for the year ended December 31, 2017. Offshore Africa crude oil production for the fourth quarter of 2018 of 22,185 bbl/d increased 14% from 19,519 bbl/d for the fourth quarter of 2017 and increased 18% from 18,802 bbl/d in the third quarter of 2018. The decrease in production for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected natural field declines. The increase in production for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 primarily reflected volumes from new wells drilled at Baobab in 2018, partially offset by the cessation of production at the Olowi field in December, together with natural field declines.

International Guidance

Annual 2018 International crude oil production of 43,627 bbl/d was above the midpoint of the Company's previously issued guidance of 42,000 to 44,000 bbl/d. First quarter 2019 International crude oil production guidance is targeted to average between 46,000 and 50,000 bbl/d. Annual International crude oil production guidance for 2019 is targeted to average between 42,000 and 46,000 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 that were stored in various storage facilities or FPSOs, as follows:

(bbl)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017
North Sea	**71,832**	881,768	—
Offshore Africa	**404,475**	868,589	121,936
	476,307	1,750,357	121,936

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Transportation	**2.94**	3.00	2.82	**3.08**	2.80
Realized sales price, net of transportation	**23.01**	54.89	50.60	**43.84**	45.77
Royalties	**0.92**	7.08	5.84	**5.08**	5.24
Production expense	**16.93**	14.47	15.03	**15.69**	14.89
Netback	**$ 5.16**	$ 33.34	$ 29.73	**$ 23.07**	$ 25.64
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76
Transportation	**0.42**	0.42	0.46	**0.47**	0.39
Realized sales price, net of transportation	**3.04**	1.90	2.09	**2.14**	2.37
Royalties	**0.10**	0.05	0.08	**0.08**	0.11
Production expense	**1.32**	1.33	1.33	**1.36**	1.27
Netback (3)	**$ 1.62**	$ 0.52	$ 0.68	**$ 0.70**	$ 0.99
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 24.04**	$ 40.77	$ 38.78	**$ 34.62**	$ 35.54
Transportation	**2.77**	2.83	2.86	**2.96**	2.66
Realized sales price, net of transportation	**21.27**	37.94	35.92	**31.66**	32.88
Royalties	**0.80**	4.44	3.75	**3.27**	3.40
Production expense	**13.51**	11.91	12.28	**12.71**	11.95
Netback	**$ 6.96**	$ 21.59	$ 19.89	**$ 15.68**	$ 17.53

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

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

(3) Natural gas netbacks exclude netbacks derived from the sale of NGLs. Combining natural gas and NGLs, the netback for the three months ended December 31, 2018 was $1.84/Mcfe (three months ended September 30, 2018 - $1.05/Mcfe, three months ended December 31, 2017 - $1.20/Mcfe; year ended December 31, 2018 - $1.18/Mcfe, year ended December 31, 2017 - $1.31/Mcfe).

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 17.03**	$ 52.45	$ 50.51	**$ 41.82**	$ 45.85
North Sea	**$ 78.45**	$ 97.77	$ 76.71	**$ 87.41**	$ 69.43
Offshore Africa	**$ 81.15**	$ 98.66	$ 73.43	**$ 90.95**	$ 67.15
Company average	**$ 25.95**	$ 57.89	$ 53.42	**$ 46.92**	$ 48.57
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.23**	$ 1.96	$ 2.33	**$ 2.33**	$ 2.58
North Sea	**$ 14.09**	$ 12.67	$ 9.77	**$ 12.08**	$ 8.24
Offshore Africa	**$ 7.32**	$ 7.78	$ 6.73	**$ 7.34**	$ 6.57
Company average	**$ 3.46**	$ 2.32	$ 2.55	**$ 2.61**	$ 2.76
Company average ($/BOE) (1) (2)	**$ 24.04**	$ 40.77	$ 38.78	**$ 34.62**	$ 35.54

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

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

North America

North America realized crude oil prices decreased 9% to $41.82 per bbl for the year ended December 31, 2018 from $45.85 per bbl for the year ended December 31, 2017. North America realized crude oil prices averaged $17.03 per bbl for the fourth quarter of 2018, a decrease of 66% compared with $50.51 per bbl for the fourth quarter of 2017, and a decrease of 68% compared with $52.45 per bbl for the third quarter of 2018. The decrease in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods was primarily due to the widening of the WCS heavy differential, which reflected a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2018 contributed approximately 174,500 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 10% to average $2.33 per Mcf for the year ended December 31, 2018 from $2.58 per Mcf for the year ended December 31, 2017. North America realized natural gas prices increased 39% to average $3.23 per Mcf for the fourth quarter of 2018 compared with $2.33 per Mcf for the fourth quarter of 2017, and increased 65% compared with $1.96 per Mcf for the third quarter of 2018. The decrease in realized natural gas prices for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected third party pipeline constraints limiting the flow of natural gas to the export market, together with increased natural gas production in the Basin. The increase in realized natural gas prices for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 primarily reflected the easing of third party pipeline constraints as well as seasonal demand factors.

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

(Quarterly Average)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 34.62**	$ 62.81	$ 54.09
Pelican Lake heavy crude oil ($/bbl)	**$ 12.40**	$ 54.57	$ 52.44
Primary heavy crude oil ($/bbl)	**$ 11.33**	$ 50.91	$ 50.71
Bitumen (thermal oil) ($/bbl)	**$ 7.70**	$ 43.54	$ 46.58
Natural gas ($/Mcf)	**$ 3.23**	$ 1.96	$ 2.33

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

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

North Sea

North Sea realized crude oil prices increased 26% to average $87.41 per bbl for the year ended December 31, 2018 from $69.43 per bbl for the year ended December 31, 2017. North Sea realized crude oil prices increased 2% to average $78.45 per bbl for the fourth quarter of 2018 from $76.71 per bbl for the fourth quarter of 2017 and decreased 20% from $97.77 per bbl for the third quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 35% to average $90.95 per bbl for the year ended December 31, 2018 from $67.15 per bbl for the year ended December 31, 2017. Offshore Africa realized crude oil prices increased 11% to average $81.15 per bbl for the fourth quarter of 2018 from $73.43 per bbl for the fourth quarter of 2017 and decreased 18% from $98.66 per bbl for the third quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2018 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 0.82**	$ 7.44	$ 6.20	**$ 5.36**	$ 5.69
North Sea	**$ 0.18**	$ 0.31	$ 0.12	**$ 0.22**	$ 0.13
Offshore Africa	**$ 3.00**	$ 8.07	$ 6.15	**$ 6.00**	$ 4.13
Company average	**$ 0.92**	$ 7.08	$ 5.84	**$ 5.08**	$ 5.24
Natural gas ($/Mcf) (1)					
North America	**$ 0.09**	$ 0.04	$ 0.07	**$ 0.07**	$ 0.11
Offshore Africa	**$ 0.80**	$ 1.20	$ 0.84	**$ 1.00**	$ 0.76
Company average	**$ 0.10**	$ 0.05	$ 0.08	**$ 0.08**	$ 0.11
Company average ($/BOE) (1)	**$ 0.80**	$ 4.44	$ 3.75	**$ 3.27**	$ 3.40

(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 months and year ended December 31, 2018 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalty rates averaged approximately 14% of product sales for the year ended December 31, 2018 compared with 13% of product sales for the year ended December 31, 2017. Crude oil and NGLs royalty rates averaged approximately 6% of product sales for the fourth quarter of 2018 compared with 13% for the fourth quarter of 2017 and 15% for the third quarter of 2018. The increase in royalty rates for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to higher realized crude oil prices for the majority of 2018, offsetting the impact of lower realized crude oil prices in the fourth quarter of 2018. The decrease in royalty rates for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected significantly lower realized crude oil prices in the fourth quarter of 2018.

Natural gas royalty rates averaged approximately 4% of product sales for the year ended December 31, 2018 compared with 5% of product sales for the year ended December 31, 2017. Natural gas royalty rates averaged approximately 3% of product sales for the fourth quarter of 2018 compared with 4% for the fourth quarter of 2017 and 2% for the third quarter of 2018. The decrease in royalty rates for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected lower realized natural gas prices. The decrease in royalty rates for the fourth quarter of 2018 from the fourth quarter of 2017 primarily reflected gas cost allowance adjustments, offsetting the impact of higher realized natural gas prices. The increase in royalty rates for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the impact of higher realized natural gas prices in the fourth quarter of 2018.

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 7% for the year ended December 31, 2018, compared with 7% of product sales for the year ended December 31, 2017. Royalty rates as a percentage of product sales averaged approximately 4% for the fourth quarter of 2018, compared with 9% of product sales for the fourth quarter of 2017 and 9% for the third quarter of 2018. 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			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 13.36**	$ 12.67	$ 12.84	**$ 13.48**	$ 12.71
North Sea	**$ 44.20**	$ 37.32	$ 44.37	**$ 39.89**	$ 36.60
Offshore Africa	**$ 32.15**	$ 19.53	$ 17.96	**$ 26.34**	$ 24.07
Company average	**$ 16.93**	$ 14.47	$ 15.03	**$ 15.69**	$ 14.89
Natural gas ($/Mcf) (1)					
North America	**$ 1.23**	$ 1.20	$ 1.26	**$ 1.25**	$ 1.19
North Sea	**$ 5.76**	$ 5.22	$ 3.98	**$ 5.29**	$ 3.37
Offshore Africa	**$ 3.00**	$ 2.69	$ 2.26	**$ 2.76**	$ 2.90
Company average	**$ 1.32**	$ 1.33	$ 1.33	**$ 1.36**	$ 1.27
Company average ($/BOE) (1)	**$ 13.51**	$ 11.91	$ 12.28	**$ 12.71**	$ 11.95

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

North America

North America crude oil and NGLs production expense for the year ended December 31, 2018 increased 6% to $13.48 per bbl from $12.71 per bbl for the year ended December 31, 2017. North America crude oil and NGLs production expense for the fourth quarter of 2018 of $13.36 per bbl increased 4% from $12.84 per bbl in the fourth quarter of 2017 and increased 5% from $12.67 per bbl for the third quarter of 2018. Crude oil and NGLs production expense for the year ended December 31, 2018 as compared with the year ended December 31, 2017 reflected increased carbon tax and energy costs in 2018 together with increased costs associated with the Company's proactive measures to voluntarily curtail crude oil production, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base. The increase per barrel for the fourth quarter of 2018 from the comparable periods reflected both lower sales volumes and increased costs associated with the curtailment of crude oil production.

North America natural gas production expense for the year ended December 31, 2018 averaged $1.25 per Mcf, an increase of 5% from $1.19 per Mcf for the year ended December 31, 2017. North America natural gas production expense for the fourth quarter of 2018 of $1.23 per Mcf was comparable with $1.26 per Mcf for the fourth quarter of 2017 and $1.20 per Mcf for the third quarter of 2018. The increase in natural gas production expense for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected the impact of lower volumes on a relatively fixed cost base due to low natural gas prices, reduced pipeline capacity as a result of a failure on a natural gas transmission line in British Columbia (T-South) in October 2018 and a turnaround at the third-party Pine River processing facility. Production expense in 2018 also reflected additional costs associated with the shut-in of production due to low natural gas pricing during 2018, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea

North Sea crude oil production expense for the year ended December 31, 2018 increased 9% to $39.89 per bbl from $36.60 per bbl for the year ended December 31, 2017. North Sea crude oil production expense of $44.20 per bbl for the fourth quarter of 2018 was comparable with $44.37 per bbl for the fourth quarter of 2017 and increased 18% from $37.32 per bbl in the third quarter of 2018. The increase in crude oil production expense for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected higher carbon tax costs and the strengthening of the UK pound sterling compared to the Canadian dollar. The increase in production expense for the fourth quarter of 2018 from the third quarter of 2018 primarily reflected the timing of liftings from various fields that have different cost structures and additional maintenance costs, together with decreased production.

Offshore Africa

Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire for the year ended December 31, 2018 was $13.30 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $26.34 per bbl. Production expense for the fourth quarter of 2018 relating to Côte d'Ivoire was $11.68 per bbl, while total crude oil production expense for the Offshore Africa segment, including the Olowi field in Gabon, was $32.15 per bbl. Total Offshore Africa crude oil production expense for the three months and year ended December 31, 2018 reflected the timing of liftings from various fields, including the Olowi field in Gabon, that have different cost structures, fluctuating production volumes on a relatively fixed cost base, and planned maintenance activities. Production expense was also impacted by movements in the Canadian dollar.

During the fourth quarter of 2018, the Gabonese Republic approved cessation of production from the Company’s Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the surrender of the permit area back to the Gabonese Republic, including associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax). In January 2019, the Company completed FPSO demobilization and sail away activities.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 929**	$ 917	$ 939	**$ 3,590**	$ 3,957
$/BOE (1)	**$ 15.50**	$ 15.11	$ 14.46	**$ 15.12**	$ 15.82

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

Depletion, depreciation and amortization per BOE for the year ended December 31, 2018 decreased 4% to $15.12 per BOE from $15.82 per BOE for the year ended December 31, 2017. Depletion, depreciation and amortization expense per BOE for the fourth quarter of 2018 increased 7% to $15.50 per BOE from $14.46 per BOE for the fourth quarter of 2017 and increased 3% from $15.11 per BOE for the third quarter of 2018.

The decrease in depletion, depreciation and amortization expense per BOE for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of additional depletion, depreciation and amortization expense in 2017 related to the abandonment of the Ninian North platform in the North Sea. The increase in depletion, depreciation and amortization expense per BOE for the fourth quarter of 2018 from the comparable periods reflected the impact of fluctuations in sales volumes from different underlying operations. The increase per BOE for the fourth quarter of 2018 from the fourth quarter of 2017 also reflected a higher depletable base in North America.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 31**	$ 31	$ 30	**$ 125**	$ 116
$/BOE (1)	**$ 0.52**	$ 0.52	$ 0.45	**$ 0.53**	$ 0.46

(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 year ended December 31, 2018 increased 15% to $0.53 per BOE from $0.46 per BOE for the year ended December 31, 2017. Asset retirement obligation accretion expense for the fourth quarter of 2018 increased 16% to $0.52 per BOE from $0.45 per BOE for the fourth quarter of 2017, and was comparable with $0.52 per BOE for the third quarter of 2018.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its expertise in capturing synergies following the acquisition completed in 2017. Production averaged 447,048 bbl/d during the fourth quarter of 2018 and 426,190 bbl/d for the year, reflecting strong, reliable operations at Horizon, together with incremental reliability at AOSP. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, adjusted cash production costs averaged $19.97 per bbl during the fourth quarter and $21.05 per bbl during the year.

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

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
SCO realized sales price (2)	**$ 42.73**	$ 81.69	$ 70.85	**$ 68.61**	$ 63.98
Bitumen value for royalty purposes (3)	**$ 29.93**	$ 51.64	$ 44.78	**$ 40.02**	$ 41.05
Bitumen royalties (4)	**$ 2.03**	$ 4.31	$ 2.45	**$ 3.09**	$ 1.64
Transportation	**$ 1.56**	$ 1.73	$ 1.88	**$ 1.61**	$ 1.54

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

(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 $68.61 per bbl for the year ended December 31, 2018, an increase of 7% from $63.98 per bbl for the year ended December 31, 2017. For the fourth quarter of 2018, the realized sales price decreased 40% to $42.73 per bbl from $70.85 per bbl for the fourth quarter of 2017 and decreased 48% from $81.69 per bbl for the third quarter of 2018. The increase in realized sales prices for the year ended December 31, 2018 from the year ended December 31, 2017 primarily reflected WTI benchmark pricing. The decrease in realized prices for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 reflected the impact of a shortage of takeaway capacity out of the Basin, resulting in increased storage levels and higher apportionment on the Enbridge Mainline system.

CASH PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Cash production costs	**$ 797**	$ 842	$ 846	**$ 3,367**	$ 2,600
Less: costs incurred during turnaround periods	**—**	(109)	(137)	**(109)**	(216)
Adjusted cash production costs	**$ 797**	$ 733	$ 709	**$ 3,258**	$ 2,384
Adjusted cash production costs, excluding natural gas costs	**$ 773**	$ 714	$ 668	**$ 3,156**	$ 2,239
Natural gas costs	**24**	19	41	**102**	145
Adjusted cash production costs	**$ 797**	$ 733	$ 709	**$ 3,258**	$ 2,384

	Three Months Ended			Year Ended	
($/bbl) (1)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Adjusted cash production costs, excluding natural gas costs	**$ 19.37**	$ 19.43	$ 23.56	**$ 20.39**	$ 21.98
Natural gas costs	**0.60**	0.52	1.43	**0.66**	1.42
Adjusted cash production costs	**$ 19.97**	$ 19.95	$ 24.99	**$ 21.05**	$ 23.40
Sales (bbl/d)	**433,970**	399,514	308,067	**424,112**	279,084

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

Adjusted cash production costs for the year ended December 31, 2018 decreased 10% to $21.05 per bbl from $23.40 per bbl for the year ended December 31, 2017. Adjusted cash production costs for the fourth quarter of 2018 averaged $19.97 per bbl, a decrease of 20% from $24.99 per bbl for the fourth quarter of 2017 and comparable with $19.95 per bbl for the third quarter of 2018. The decrease in adjusted cash production costs per barrel for the three months and year ended December 31, 2018 from the comparable periods in 2017 primarily reflected the Company's high utilization rates and reliability and the capture of cost synergies between the operations, as well as additional capacity from Phase 3 production at Horizon and the acquisition of AOSP.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 396**	$ 385	$ 464	**$ 1,557**	$ 1,220
Less: depreciation incurred during turnaround period	**—**	(56)	(188)	**(56)**	(213)
Adjusted depletion, depreciation and amortization	**$ 396**	$ 329	$ 276	**$ 1,501**	$ 1,007
$/bbl (1)	**$ 9.92**	$ 8.96	$ 9.75	**$ 9.70**	$ 9.89

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

Adjusted depletion, depreciation and amortization expense per barrel for the Oil Sands Mining and Upgrading segment for the year ended December 31, 2018 decreased 2% to $9.70 per bbl from $9.89 per bbl for the year ended December 31, 2017. Adjusted depletion, depreciation and amortization expense per barrel for the fourth quarter of 2018 of $9.92 per bbl increased 2% from $9.75 per bbl for the fourth quarter of 2017, and increased 11% from $8.96 per bbl for the third quarter of 2018.

The decrease in adjusted depletion, depreciation and amortization expense per barrel for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to the impact of AOSP, which has a lower depletion rate. The increase in adjusted depletion, depreciation and amortization expense per barrel for the fourth quarter of 2018 from the fourth quarter of 2017 and the third quarter of 2018 was primarily due to the impact of fluctuations in sales volumes from different underlying operations, with a higher proportion of sales during the fourth quarter of 2017 and third quarter of 2018 subject to a lower depletion rate, as compared with the fourth quarter of 2018.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Expense	**$ 15**	$ 16	$ 15	**$ 61**	$ 48
$/bbl [1]	**$ 0.38**	$ 0.41	$ 0.53	**$ 0.40**	$ 0.47

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

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

Asset retirement obligation accretion expense per bbl for the year ended December 31, 2018 decreased 15% to $0.40 per bbl from $0.47 per bbl for the year ended December 31, 2017 due to higher sales volumes. Asset retirement obligation accretion expense of $0.38 per bbl for the fourth quarter of 2018 decreased 28% from $0.53 per bbl for the fourth quarter of 2017 and decreased 7% from $0.41 per bbl for the third quarter of 2018, primarily due to higher sales volumes.

MIDSTREAM

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Revenue	**$ 24**	$ 26	$ 28	**$ 102**	$ 102
Less:					
Production expense	**5**	5	4	**21**	16
Depreciation	**3**	4	3	**14**	9
Equity loss (gain) on investment	**—**	2	1	**5**	(31)
Gain on revaluation of properties [1]	**—**	—	—	**—**	(114)
Segment earnings before taxes	**$ 16**	$ 15	$ 20	**$ 62**	$ 222

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

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

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase, with completion targeted for the second quarter of 2019. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to maintain the agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 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 toll, 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 December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
Expense	**$ 91**	$ 77	$ 84	**$ 325**	$ 319
$/BOE (1)	**$ 0.91**	$ 0.79	$ 0.90	**$ 0.83**	$ 0.91

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

Administration expense per BOE for the year ended December 31, 2018 decreased 9% to $0.83 per BOE from $0.91 per BOE for the year ended December 31, 2017. Administration expense for the fourth quarter of 2018 of $0.91 per BOE was comparable with $0.90 per BOE for the fourth quarter of 2017 and increased 15% from $0.79 per BOE for the third quarter of 2018. Administration expense per BOE decreased for the year ended December 31, 2018 from the year ended December 31, 2017 primarily due to higher sales volumes. The increase in the fourth quarter of 2018 from the third quarter of 2018 was primarily due to higher personnel and other corporate costs.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
(Recovery) expense	**$ (148)**	$ (85)	$ 97	**$ (146)**	$ 134

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 an $146 million share-based compensation recovery for the year ended December 31, 2018, primarily as a result of remeasurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period and changes in the Company's share price. Included within the share-based compensation recovery for the year ended December 31, 2018 was an expense of $8 million related to performance share units granted to certain executive employees (December 31, 2017 – $5 million). For the year ended December 31, 2018, the Company recovered $19 million of share-based compensation costs from the Oil Sands Mining and Upgrading segment (December 31, 2017 – $14 million costs charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended **Dec 31 2018**	Sep 30 2018	Dec 31 2017	Year Ended **Dec 31 2018**	Dec 31 2017
Expense, gross	**$ 198**	$ 198	$ 187	**$ 808**	$ 713
Less: capitalized interest	**19**	18	18	**69**	82
Expense, net	**$ 179**	$ 180	$ 169	**$ 739**	$ 631
$/BOE (1)	**$ 1.78**	$ 1.85	$ 1.81	**$ 1.88**	$ 1.79
Average effective interest rate	**4.1%**	4.0%	3.7%	**3.9%**	3.8%

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

Gross interest and other financing expense for the three months and year ended December 31, 2018 increased from the comparable periods in 2017 primarily due to the impact of higher average debt levels as a result of acquisitions completed in 2017 and higher interest rates in 2018. Gross interest and other financing expense for the fourth quarter of 2018 was comparable with the third quarter of 2018. Capitalized interest of $69 million for the year ended December 31, 2018 was primarily related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the year ended December 31, 2018 increased 5% to $1.88 per BOE from $1.79 per BOE for the year ended December 31, 2017. Net interest and other financing expense per BOE for the fourth quarter of 2018 decreased 2% to $1.78 per BOE from $1.81 per BOE for the fourth quarter of 2017 and decreased 4% from $1.85 per BOE for the third quarter of 2018. The increase in net interest and other financing expense per BOE for the year ended December 31, 2018 from the year ended December 31, 2017 was primarily due to higher average debt levels as a result of acquisitions completed in 2017 and lower capitalized interest related to the completion of Horizon Phase 3. The decrease for the fourth quarter of 2018 from the comparable periods was primarily due to higher sales volumes and lower average debt levels in the fourth quarter of 2018.

The Company's average effective interest rate for the year ended December 31, 2018 was consistent with the year ended December 31, 2017. The increase for the fourth quarter of 2018 from the fourth quarter of 2017 reflected the impact of higher benchmark interest rates on the Company's outstanding bank credit facilities.

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			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Crude oil and NGLs financial instruments	**$ (27)**	$ —	$ —	**$ (27)**	$ (32)
Natural gas financial instruments	**2**	6	(2)	**5**	(7)
Foreign currency contracts	**(20)**	(14)	(71)	**(77)**	37
Realized gain	**(45)**	(8)	(73)	**(99)**	(2)
Crude oil and NGLs financial instruments	**41**	(25)	7	**16**	—
Natural gas financial instruments	**(6)**	(14)	2	**(4)**	(6)
Foreign currency contracts	**(8)**	18	66	**(47)**	43
Unrealized loss (gain)	**27**	(21)	75	**(35)**	37
Net (gain) loss	**$ (18)**	$ (29)	$ 2	**$ (134)**	$ 35

During the year ended December 31, 2018, net realized risk management gains were related to the settlement of foreign currency contracts and crude oil and NGLs financial instruments. The Company recorded a net unrealized gain of $35 million ($36 million after-tax) on its risk management activities for the year ended December 31, 2018, including an unrealized loss of $27 million ($17 million after-tax) for the fourth quarter of 2018 (September 30, 2018 – unrealized gain of $21 million, $11 million after-tax; December 31, 2017 – unrealized loss of $75 million, $68 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2018 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Net realized (gain) loss	**$ (2)**	$ 14	$ (15)	**$ 121**	$ 34
Net unrealized loss (gain)	**548**	(182)	(2)	**706**	(821)
Net loss (gain) [1]	**$ 546**	$ (168)	$ (17)	**$ 827**	$ (787)

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

The net realized foreign exchange loss for the year ended December 31, 2018 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized foreign exchange loss for the year ended December 31, 2018 was primarily related to the impact of the weakening Canadian dollar with respect to outstanding US dollar debt, partially offset by the reversal of the net unrealized foreign exchange loss on the repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes. The net unrealized loss (gain) for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2018 – unrealized gain of $76 million, September 30, 2018 – unrealized loss of $23 million, December 31, 2017 – unrealized gain of $1 million; year ended December 31, 2018 – unrealized gain of $118 million, December 31, 2017 – unrealized loss of $280 million). The US/Canadian dollar exchange rate at December 31, 2018 was US$0.7328 (September 30, 2018 – US$0.7738, December 31, 2017 – US$0.7988).

INCOME TAXES

	Three Months Ended			Year Ended	
($ millions, except income tax rates)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
North America [1]	**$ (254)**	$ 169	$ (93)	**$ 312**	$ (145)
North Sea	**8**	12	10	**28**	57
Offshore Africa	**11**	22	17	**54**	45
PRT – North Sea	**—**	(9)	(25)	**(29)**	(132)
Other taxes	**1**	3	3	**9**	11
Current income tax (recovery) expense	**(234)**	197	(88)	**374**	(164)
Deferred corporate income tax expense	**112**	145	307	**540**	586
Deferred PRT expense – North Sea	**(1)**	1	(13)	**17**	54
Deferred income tax expense	**111**	146	294	**557**	640
	(123)	343	206	**931**	476
Income tax rate and other legislative changes [2]	**—**	—	(10)	**—**	(10)
	$ (123)	$ 343	$ 196	**$ 931**	$ 466
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**33%**	19%	32%	**21%**	27%

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

(2) During the fourth quarter of 2017, the British Columbia government enacted legislation that increased the provincial corporate income tax rate from 11% to 12% effective January 1, 2018, resulting in an increase in the Company's deferred income tax liability of $10 million.

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

The effective income tax rate for the three months and year ended December 31, 2018 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current PRT recovery in the North Sea for the year ended December 31, 2018 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the Murchison and Ninian North platforms.

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

For 2019, current income tax expense is targeted to range from $300 million to $400 million in Canada and $55 million to $85 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2018	Sep 30 2018	Dec 31 2017	Year Ended Dec 31 2018	Dec 31 2017
Exploration and Evaluation					
Net (proceeds) expenditures [2] [3] [4]	**$ (95)**	$ 79	$ 16	**$ 48**	$ 149
Property, Plant and Equipment					
Net property acquisitions [2] [3] [4]	**1**	5	19	**98**	1,219
Well drilling, completion and equipping	**359**	416	212	**1,446**	1,001
Production and related facilities	**365**	325	258	**1,262**	860
Capitalized interest and other [5]	**32**	26	27	**106**	91
Net expenditures	**757**	772	516	**2,912**	3,171
Total Exploration and Production	**662**	851	532	**2,960**	3,320
Oil Sands Mining and Upgrading					
Project costs [6]	**178**	131	248	**438**	821
Sustaining capital	**235**	173	214	**665**	561
Turnaround costs	**12**	41	69	**112**	155
Acquisitions of Exploration and Evaluation assets [2] [4] [7]	**—**	218	—	**218**	219
Net property acquisitions [2] [4]	**—**	—	—	**—**	11,604
Capitalized interest and other [5]	**(8)**	(3)	26	**14**	76
Total Oil Sands Mining and Upgrading	**417**	560	557	**1,447**	13,436
Midstream	**2**	2	2	**13**	80
Abandonments [8]	**93**	57	63	**290**	274
Head office	**7**	3	(11)	**21**	19
Total net capital expenditures	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129
By segment					
North America [2] [3] [4]	**$ 604**	$ 727	$ 444	**$ 2,671**	$ 3,056
North Sea [3]	**58**	35	52	**131**	160
Offshore Africa [3]	**—**	89	36	**158**	104
Oil Sands Mining and Upgrading [4] [7]	**417**	560	557	**1,447**	13,436
Midstream	**2**	2	2	**13**	80
Abandonments [8]	**93**	57	63	**290**	274
Head office	**7**	3	(11)	**21**	19
Total	**$ 1,181**	$ 1,473	$ 1,143	**$ 4,731**	$ 17,129

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

(2) Includes business combinations.

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

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

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

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

(7) In the fourth quarter of 2018, following integration of the Joslyn oil sands project into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant, and equipment.

(8) 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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2018**	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Cash flows used in investing activities	***$ 1,042***	*$ 1,265*	*$ 1,074*	***$ 4,814***	*$ 13,102*
Net change in non-cash working capital (1)	***46***	*151*	*49*	***(345)***	*22*
Investment in other long-term assets	**—**	—	*(43)*	***(28)***	*(87)*
Share consideration in business acquisitions	**—**	—	—	**—**	*3,818*
Abandonment expenditures (2)	***93***	*57*	*63*	***290***	*274*
Net capital expenditures	***$ 1,181***	*$ 1,473*	*$ 1,143*	***$ 4,731***	*$ 17,129*

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

(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 year ended December 31, 2018 decreased to $4,731 million compared with $17,129 million for the year ended December 31, 2017. Net capital expenditures for the year ended December 31, 2017 included $12,157 million related to the acquisition of AOSP and other assets and $921 million related to the acquisition of assets in the Greater Pelican Lake region and other miscellaneous assets. Net capital expenditures for the fourth quarter of 2018 were $1,181 million, compared with $1,143 million for the fourth quarter of 2017 and $1,473 million for the third quarter of 2018.

Net capital expenditures for the year ended December 31, 2018 included:

- $105 million (US$79 million) of proceeds for the disposal of a 30% interest in the exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs in the Offshore Africa segment;
- $218 million of consideration for the acquisition of the Joslyn oil sands project in the Oil Sands Mining and Upgrading segment (comprising $100 million cash on closing with the remaining balance paid equally over the next five years);
- $22 million of cash consideration for the acquisition of Laricina Energy Ltd. in the North America Exploration and Production segment (net of $24 million of cash acquired); and
- $73 million of cash proceeds for the acquisition of the remaining interest at the Ninian field in the North Sea.

2019 Capital Budget

On December 5, 2018, the Company announced its 2019 Capital Budget. The 2019 budget targets a base capital program of $3,700 million, including $3,100 million to maintain current production levels and approximately $600 million directed toward long-term growth projects. The Company maintains capital flexibility in its 2019 budget. Should market access conditions improve, the Company has the capability to adjust 2019 capital spending.

Drilling Activity

(number of net wells)	Three Months Ended			Year Ended	
	Dec 31 2018	Sep 30 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Net successful natural gas wells	**3**	6	2	**18**	21
Net successful crude oil wells [(1)]	**102**	178	125	**483**	495
Dry wells	**2**	5	3	**9**	7
Stratigraphic test / service wells	**91**	47	51	**615**	289
Total	**198**	236	181	**1,125**	812
Success rate (excluding stratigraphic test / service wells)	**98%**	97%	98%	**98%**	99%

(1) Includes bitumen wells.

North America

During the fourth quarter of 2018, the Company targeted 3 net natural gas wells in Northwest Alberta. The Company also targeted 103 net crude oil wells. The majority of these net wells were concentrated in the Company's Northern Plains region where 24 primary heavy crude oil wells, 41 bitumen (thermal oil) wells, 4 Pelican Lake heavy crude oil wells and 1 light crude oil well were drilled. Another 33 wells targeting light crude oil were drilled outside the Northern Plains region.

The Company's strategic and proactive decisions and its ability to utilize capital flexibility based on its large, balanced and diverse asset base has been reflected in the North America drilling program. During 2018, the Company reallocated capital spending from primary heavy crude oil to light crude oil, with an increase of 32 net wells in light crude oil and a corresponding decrease of 137 net wells in primary heavy crude oil.

North Sea

During the year ended December 31, 2018, the Company completed four gross production wells and one gross injection well (4.9 on a net basis), successfully completing the 2018 drilling program in the North Sea.

Offshore Africa

During the fourth quarter of 2018, the Company completed two gross production wells (1.2 on a net basis) at Baobab (year ended December 31, 2018 – three gross production wells (1.7 on a net basis)).

The Company has retained a 20% working interest in Block 11B/12B, off the southern coast of South Africa. In late December, the operator of the exploration right commenced the drilling of an exploratory well. Subsequent to December 31, 2018, the operator announced that drilling results indicate the presence of natural gas condensate. The Company expects the cost of the current exploration well to be fully carried pursuant to two separate farm-out agreements that were completed in 2018.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Dec 31 2018	Sep 30 2018	Dec 31 2017
Working capital [1]	**$ (601)**	$ 111	$ 513
Long-term debt [2] [3]	**$ 20,623**	$ 19,733	$ 22,458
Less: cash and cash equivalents	**101**	296	137
Long-term debt, net	**$ 20,522**	$ 19,437	$ 22,321
Share capital	**$ 9,323**	$ 9,393	$ 9,109
Retained earnings	**22,529**	24,033	22,612
Accumulated other comprehensive income (loss)	**122**	(33)	(68)
Shareholders' equity	**$ 31,974**	$ 33,393	$ 31,653
Debt to book capitalization [3] [4]	**39.1%**	36.8%	41.4%
Debt to market capitalization [3] [5]	**34.1%**	27.4%	28.9%
After-tax return on average common shareholders' equity [6]	**8.0%**	11.6%	8.0%
After-tax return on average capital employed [3] [7]	**5.9%**	8.0%	5.6%

(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 December 31, 2018, 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, 2017. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings as determined by independent rating agencies, and the conditions of the market. The Company continues to believe that its internally generated 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;
- For the year ended December 31, 2018, the Company utilized cash flows from operating activities to facilitate net repayment of bank credit facilities and US dollar debt securities of $3,312 million, excluding the impact of foreign exchange on debt balances, including:
    - repayment and cancellation of the $125 million non-revolving credit facility;
    - repayment and cancellation of $1,200 million of the $3,000 million non-revolving credit facility; and
    - repayment of US$600 million of 1.75% notes and US$400 million of 5.90% notes.
- Additionally, the Company utilized available liquidity to settle the deferred payment to Marathon for $481 million, resulting in total net repayments of debt of $2,831 million.

- Reviewing the Company's borrowing capacity:
  - During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - During the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.
  - During the first quarter of 2018, the Company extended the $750 million non-revolving credit facility originally due in February 2019 to February 2021. Borrowings under the $750 million non-revolving term credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US $2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
  - In July 2017, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default.

As at December 31, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2018, the Company had total US dollar denominated debt with a carrying amount of $14,611 million (US$10,708 million), before transaction costs and original issue discounts. This included $5,604 million (US$4,108 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,058 million). The fixed repayment amount of these hedging instruments is $5,256 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $348 million to $14,263 million as at December 31, 2018.

Net long-term debt was $20,522 million at December 31, 2018, resulting in a debt to book capitalization ratio of 39.1% (December 31, 2017 – 41.4%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when 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 December 31, 2018 are discussed in note 9 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2018, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at December 31, 2018, 28,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for January to March 2019 and 8,000 bbl/d were hedged for January to September

2019. Additionally, 10,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January to March 2019, 30,000 GJ/d were hedged using AECO fixed price swaps for January to March 2019 and 10,000 GJ/d were hedged for April to October 2019. Subsequent to December 31, 2018, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for April to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2018 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

Share Capital

As at December 31, 2018, there were 1,201,886,000 common shares outstanding (December 31, 2017 – 1,222,769,000 common shares) and 46,685,000 stock options outstanding. As at March 5, 2019, the Company had 1,199,849,000 common shares outstanding and 50,413,000 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. On February 28, 2018, the Board of Directors approved an increase in the quarterly dividend to $0.335 per common share, beginning with the dividend payable on April 1, 2018 (previous quarterly dividend rate of $0.275 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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

For the year ended December 31, 2018, the Company purchased for cancellation 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has entered into various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at December 31, 2018:

($ millions)	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$ 692	$ 664	$ 620	$ 516	$ 381	$ 3,991
North West Redwater Partnership debt service toll [1]	$ 86	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore equipment operating leases	$ 94	$ 73	$ 75	$ 8	$ —	$ —
Long-term debt [2]	$ 1,141	$ 5,996	$ 1,444	$ 1,003	$ 1,365	$ 9,793
Interest and other financing expense [3]	$ 836	$ 755	$ 610	$ 558	$ 500	$ 5,327
Office leases	$ 42	$ 42	$ 39	$ 31	$ 32	$ 89
Other	$ 85	$ 35	$ 32	$ 32	$ 31	$ 424

(1) *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 service toll is $1,301 million of interest payable over the 30 year tolling period.*

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

(3) *Interest and other financing payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2018.*

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

For the impact of new accounting standards, refer to the audited consolidated financial statements for the year ended December 31, 2017 and the unaudited interim consolidated financial statements for the three months and year ended December 31, 2018.

ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company has determined that these amendments have no significant impact on its 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 interpretation is effective January 1, 2019. The Company has determined that this interpretation has no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaces IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires 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 may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method 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 will not be restated.

On initial adoption, the Company intends to use 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 will be treated as short-term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

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

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company’s applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements. In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 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 will be recognized in the consolidated statements of earnings.

The Company continues to finalize its evaluation of its contracts that are potentially leases under IFRS 16, as well as implementing changes to policies, internal controls, information systems, and business accounting processes.

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, 2017.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Dec 31 2018	Dec 31 2017
ASSETS			
Current assets			
Cash and cash equivalents		**$ 101**	$ 137
Accounts receivable		**1,148**	2,397
Current income taxes receivable		**—**	322
Inventory		**955**	894
Prepaids and other		**176**	175
Investments	7	**524**	893
Current portion of other long-term assets	8	**116**	79
		3,020	4,897
Exploration and evaluation assets	4	**2,637**	2,632
Property, plant and equipment	5	**64,559**	65,170
Other long-term assets	8	**1,343**	1,168
		$ 71,559	$ 73,867
LIABILITIES			
Current liabilities			
Accounts payable		**$ 779**	$ 775
Accrued liabilities		**2,356**	2,597
Current income taxes payable		**151**	—
Current portion of long-term debt	9	**1,141**	1,877
Current portion of other long-term liabilities	10	**335**	1,012
		4,762	6,261
Long-term debt	9	**19,482**	20,581
Other long-term liabilities	10	**3,890**	4,397
Deferred income taxes		**11,451**	10,975
		39,585	42,214
SHAREHOLDERS' EQUITY			
Share capital	12	**9,323**	9,109
Retained earnings		**22,529**	22,612
Accumulated other comprehensive income (loss)	13	**122**	(68)
		31,974	31,653
		$ 71,559	$ 73,867

Commitments and contingencies (note 17).

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

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Dec 31 2018**	Three Months Ended Dec 31 2017	Year Ended **Dec 31 2018**	Year Ended Dec 31 2017
Product sales	18	**$ 3,831**	$ 5,516	**$ 22,282**	$ 18,360
Less: royalties		**(129)**	(313)	**(1,255)**	(1,018)
Revenue		**3,702**	5,203	**21,027**	17,342
Expenses					
Production		**1,627**	1,664	**6,464**	5,675
Transportation, blending and feedstock		**864**	1,161	**4,189**	3,529
Depletion, depreciation and amortization	5	**1,328**	1,406	**5,161**	5,186
Administration		**91**	84	**325**	319
Share-based compensation	10	**(148)**	97	**(146)**	134
Asset retirement obligation accretion	10	**46**	45	**186**	164
Interest and other financing expense		**179**	169	**739**	631
Risk management activities	16	**(18)**	2	**(134)**	35
Foreign exchange loss (gain)		**546**	(17)	**827**	(787)
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(41)**	—	**(452)**	(379)
Loss (gain) from investments	7, 8	**127**	(10)	**346**	(38)
		4,601	4,601	**17,505**	14,469
Earnings (loss) before taxes		**(899)**	602	**3,522**	2,873
Current income tax (recovery) expense	11	**(234)**	(88)	**374**	(164)
Deferred income tax expense	11	**111**	294	**557**	640
Net earnings (loss)		**$ (776)**	$ 396	**$ 2,591**	$ 2,397
Net earnings (loss) per common share					
Basic	15	**$ (0.64)**	$ 0.32	**$ 2.13**	$ 2.04
Diluted	15	**$ (0.64)**	$ 0.32	**$ 2.12**	$ 2.03

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Dec 31 2018**	Three Months Ended Dec 31 2017	Year Ended **Dec 31 2018**	Year Ended Dec 31 2017
Net earnings (loss)	**$ (776)**	$ 396	**$ 2,591**	$ 2,397
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2017 – $nil) – three months ended; $nil (2017 – $9 million) – year ended	**12**	(7)	**5**	53
Reclassification to net earnings (loss), net of taxes of $1 million (2017 – $1 million) – three months ended; $6 million (2017 – $5 million) – year ended	**(8)**	(4)	**(39)**	(33)
	4	(11)	**(34)**	20
Foreign currency translation adjustment				
Translation of net investment	**151**	—	**224**	(158)
Other comprehensive income (loss), net of taxes	**155**	(11)	**190**	(138)
Comprehensive income (loss)	**$ (621)**	$ 385	**$ 2,781**	$ 2,259

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2018	Dec 31 2017
Share capital	12		
Balance – beginning of year		**$ 9,109**	$ 4,671
Issued for the acquisition of AOSP and other assets [1]	6	**—**	3,818
Issued upon exercise of stock options		**332**	466
Previously recognized liability on stock options exercised for common shares		**120**	154
Purchase of common shares under Normal Course Issuer Bid		**(238)**	—
Balance – end of year		**9,323**	9,109
Retained earnings			
Balance – beginning of year		**22,612**	21,526
Net earnings		**2,591**	2,397
Purchase of common shares under Normal Course Issuer Bid	12	**(1,044)**	—
Dividends on common shares	12	**(1,630)**	(1,311)
Balance – end of year		**22,529**	22,612
Accumulated other comprehensive income (loss)	13		
Balance – beginning of year		**(68)**	70
Other comprehensive income (loss), net of taxes		**190**	(138)
Balance – end of year		**122**	(68)
Shareholders' equity		**$ 31,974**	$ 31,653

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2018	Three Months Ended Dec 31 2017	Year Ended Dec 31 2018	Year Ended Dec 31 2017
Operating activities					
Net earnings (loss)		**$ (776)**	$ 396	**$ 2,591**	$ 2,397
Non-cash items					
Depletion, depreciation and amortization		**1,328**	1,406	**5,161**	5,186
Share-based compensation		**(148)**	97	**(146)**	134
Asset retirement obligation accretion		**46**	45	**186**	164
Unrealized risk management loss (gain)		**27**	75	**(35)**	37
Unrealized foreign exchange loss (gain)		**548**	(2)	**706**	(821)
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**146**	—
Gain on acquisition, disposition and revaluation of properties	4, 5, 6	**(41)**	—	**(452)**	(379)
Loss (gain) from investments	7, 8	**134**	(4)	**374**	(11)
Deferred income tax expense		**111**	294	**557**	640
Other		**(18)**	(97)	**(23)**	(110)
Abandonment expenditures		**(93)**	(63)	**(290)**	(274)
Net change in non-cash working capital		**279**	(709)	**1,346**	299
Cash flows from (used in) operating activities		**1,397**	1,438	**10,121**	7,262
Financing activities					
Issue (repayment) of bank credit facilities and commercial paper, net	9	**252**	(390)	**(1,595)**	2,222
Issue of medium-term notes, net	9	**—**	—	**—**	1,791
(Repayment) issue of US dollar debt securities, net	9	**—**	—	**(1,236)**	2,733
Issue of common shares on exercise of stock options		**12**	186	**332**	466
Purchase of common shares under Normal Course Issuer Bid		**(408)**	—	**(1,282)**	—
Dividends on common shares		**(406)**	(335)	**(1,562)**	(1,252)
Cash flows (used in) from financing activities		**(550)**	(539)	**(5,343)**	5,960
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets		**95**	(16)	**(266)**	(124)
Net expenditures on property, plant and equipment		**(1,183)**	(1,064)	**(4,175)**	(4,574)
Acquisition of AOSP and other assets, net of cash acquired [(1)]	6	**—**	—	**—**	(8,630)
Investment in other long-term assets		**—**	(43)	**(28)**	(87)
Net change in non-cash working capital		**46**	49	**(345)**	313
Cash flows used in investing activities		**(1,042)**	(1,074)	**(4,814)**	(13,102)
(Decrease) increase in cash and cash equivalents		**(195)**	(175)	**(36)**	120
Cash and cash equivalents – beginning of period		**296**	312	**137**	17
Cash and cash equivalents – end of period		**$ 101**	$ 137	**$ 101**	$ 137
Interest paid, net		**$ 204**	$ 185	**$ 911**	$ 725
Income taxes (received) paid		**$ (30)**	$ 12	**$ (225)**	$ (792)

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

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

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

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

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

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

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

2. CHANGES IN ACCOUNTING POLICIES

IFRS 15 "Revenue from Contracts with Customers"

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

The Company adopted IFRS 15 on January 1, 2018 using the retrospective with cumulative effect method. The Company continues to account for revenue for the year ended December 31, 2017 in accordance with the Company's previous accounting policy for revenue and cost of goods sold. There were no changes to reported net earnings or retained earnings as a result of adopting IFRS 15. Under the standard, the Company is required to provide additional disclosure of disaggregated revenue by major product type. In connection with adoption of the standard, the Company has reclassified certain comparative amounts in a manner consistent with the presentation adopted for the year ended December 31, 2018 (see note 18).

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

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

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

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

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

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

IFRS 9 "Financial Instruments"

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

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

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

At each reporting date, on a forward looking basis, the Company assesses the expected credit losses associated with its financial assets carried at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the Company and the cash flows that the Company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and internal credit assessments of the customers. Credit risk for longer-term receivables is assessed based on an external credit rating of the counterparty. For longer-term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12-month expected credit loss.

Changes in the provision for expected credit loss are recognized in net earnings.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments also permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments are effective January 1, 2020 with earlier adoption permitted. The amendments apply to business combinations after the date of adoption. The Company is assessing the impact of these amendments on its consolidated financial statements.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The amendments are effective January 1, 2020 with earlier adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

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 joint venture. The amendments are effective January 1, 2019 with earlier adoption permitted. The amendments are required to be adopted retrospectively. The Company has determined that these amendments will have no significant impact on its 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 interpretation is effective January 1, 2019. The Company has determined that this interpretation will have no significant impact on its consolidated financial statements.

IFRS 16 "Leases"

In January 2016, the IASB issued IFRS 16 “Leases”, which provides guidance on accounting for leases. The new standard replaces IAS 17 “Leases” and related interpretations. IFRS 16 eliminates the distinction between operating leases and financing leases for lessees and requires 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 may continue to be treated as an expense. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are exempt from the standard.

The Company will adopt IFRS 16 on January 1, 2019 using the retrospective with cumulative effect method 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 will not be restated.

On initial adoption, the Company intends to use 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 will be treated as short-term leases; and
- exclusion of indirect costs for the measurement of lease assets at the date of initial application.

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

On adoption of IFRS 16, the Company will recognize lease assets and liabilities at the present value of the remaining lease payments, discounted using the Company’s applicable borrowing rate on January 1, 2019. The Company expects to report additional lease assets and corresponding liabilities of between $1.5 billion and $1.6 billion. The Company continues to finalize its accounting for leases in accordance with IFRS 16, and the above estimates are subject to change based on finalization of the Company's review of its lease arrangements. In the statement of earnings, depletion, depreciation and amortization expense and interest expense will increase, with corresponding decreases in production, transportation and administration expenses. The Company does not expect to report a material impact on net earnings. Under the new standard, the Company will report cash outflows for repayment of the principal portion of the lease liability as cash flows from financing activities. The interest portion of the lease payments will continue to be classified as cash flows from operating activities.

Where the Company, acting as the operator, signs a lease on behalf of a joint operation and assumes the legal liability for that lease, the Company will recognize 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 will be recognized in the consolidated statements of earnings.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2017	$ 2,282	$ —	$ 91	$ 259	$ 2,632
Additions/Acquisitions	**245**	**—**	**35**	**222**	**502**
Transfers to property, plant and equipment	**(175)**	**—**	**—**	**(222)**	**(397)**
Disposals/derecognitions and other	**(4)**	**—**	**(89)**	**(7)**	**(100)**
At December 31, 2018	**$ 2,348**	**$ —**	**$ 37**	**$ 252**	**$ 2,637**

During the year ended December 31, 2018, the Company acquired a number of exploration and evaluation properties in the Oil Sands Mining and Upgrading and North America Exploration and Production segments.

In the Oil Sands Mining and Upgrading segment, the Company acquired the Joslyn oil sands project including exploration and evaluation assets of $222 million and associated asset retirement obligations of $4 million. Total consideration of $218 million was comprised of $100 million cash on closing with the remaining balance paid equally over each of the next five years. In the fourth quarter of 2018, following integration of the acquired assets into the Horizon mine plan and determination of proved crude oil reserves, the exploration and evaluation assets were transferred to property, plant and equipment. The above amounts are estimates, and may be subject to change based on the receipt of new information.

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

During the fourth quarter of 2018, the Company completed two additional farm-out agreements in the Offshore Africa segment to dispose of a combined 30% interest in its exploration right in South Africa, comprised of exploration and evaluation assets of $89 million, including a recovery of $14 million of past incurred costs, for net proceeds of $105 million (US$79 million), resulting in a pre-tax gain of $16 million ($12 million after-tax). The Company retains a 20% working interest in the exploration right following the completion of these farm-out agreements.

Under the terms of the various agreements, in the event of a commercial crude oil discovery on the exploration right and conversion to a production right, additional cash payments of between US$623 million and US$645 million will be made to the Company. In the event of a commercial natural gas discovery on the exploration right and conversion to a production right, additional payments of between US$126 million and US$132 million will be made to the Company.

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2017	$ 64,816	$ 7,126	$ 4,881	$ 42,084	$ 428	$ 414	$ 119,749
Additions	**2,428**	**237**	**212**	**1,050**	**13**	**21**	**3,961**
Transfers from E&E assets	**175**	**—**	**—**	**222**	**—**	**—**	**397**
Disposals/derecognitions and other	**(412)**	**(703)**	**(70)**	**(209)**	**—**	**—**	**(1,394)**
Foreign exchange adjustments and other	**—**	**661**	**448**	**—**	**—**	**—**	**1,109**
At December 31, 2018	**$ 67,007**	**$ 7,321**	**$ 5,471**	**$ 43,147**	**$ 441**	**$ 435**	**$ 123,822**
Accumulated depletion and depreciation							
At December 31, 2017	$ 41,151	$ 5,653	$ 3,719	$ 3,628	$ 124	$ 304	$ 54,579
Expense	**3,111**	**257**	**201**	**1,557**	**14**	**21**	**5,161**
Disposals/derecognitions	**(393)**	**(703)**	**(70)**	**(209)**	**—**	**—**	**(1,375)**
Foreign exchange adjustments and other	**12**	**528**	**353**	**5**	**—**	**—**	**898**
At December 31, 2018	**$ 43,881**	**$ 5,735**	**$ 4,203**	**$ 4,981**	**$ 138**	**$ 325**	**$ 59,263**
Net book value							
- at December 31, 2018	**$ 23,126**	**$ 1,586**	**$ 1,268**	**$ 38,166**	**$ 303**	**$ 110**	**$ 64,559**
- at December 31, 2017	$ 23,665	$ 1,473	$ 1,162	$ 38,456	$ 304	$ 110	$ 65,170

Project costs not subject to depletion and depreciation	Dec 31 2018	Dec 31 2017
Kirby Thermal Oil Sands – North	**$ 1,424**	$ 944

During the year ended December 31, 2018, the Company acquired a number of producing crude oil and natural gas properties in the North America and North Sea Exploration and Production segments. These transactions were accounted for using the acquisition method of accounting. Gains reported on the acquisitions represent the excess of the fair value of the net assets acquired compared to total purchase consideration.

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

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

During the fourth quarter of 2018, the Gabonese Republic agreed to cessation of production from the Company's Olowi field, as well as the terms of termination of the Olowi Production Sharing Contract and the return of the permit area back to the Gabonese Republic, including the associated asset retirement obligations of $69 million. The transaction resulted in a pre-tax gain on disposition of property of $20 million ($14 million after-tax).

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 year ended December 31, 2018, pre-tax interest of $69 million (December 31, 2017 – $82 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (December 31, 2017 – 3.8%).

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

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

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

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

7. INVESTMENTS

As at December 31, 2018, the Company had the following investments:

	Dec 31 2018	Dec 31 2017
Investment in PrairieSky Royalty Ltd.	**$ 400**	$ 726
Investment in Inter Pipeline Ltd.	**124**	167
	$ 524	$ 893

Investment in PrairieSky Royalty Ltd.

The Company’s investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2018, the Company’s investment in PrairieSky was classified as a current asset.

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

	Three Months Ended		Year Ended	
	Dec 31 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Fair value loss (gain) from PrairieSky	**$ 114**	$ (4)	**$ 326**	$ (3)
Dividend income from PrairieSky	**(4)**	(4)	**(17)**	(17)
	$ 110	$ (8)	**$ 309**	$ (20)

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, remeasured at each reporting date. As at December 31, 2018, the Company's investment in Inter Pipeline was classified as a current asset.

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

	Three Months Ended		Year Ended	
	Dec 31 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Fair value loss (gain) from Inter Pipeline	**$ 20**	$ (1)	**$ 43**	$ 23
Dividend income from Inter Pipeline	**(3)**	(2)	**(11)**	(10)
	$ 17	$ (3)	**$ 32**	$ 13

8. OTHER LONG-TERM ASSETS

	Dec 31 2018	Dec 31 2017
Investment in North West Redwater Partnership	**$ 287**	$ 292
North West Redwater Partnership subordinated debt [1]	**591**	510
Risk management (note 16)	**373**	204
Other	**208**	241
	1,459	1,247
Less: current portion	**116**	79
	$ 1,343	$ 1,168

(1) Includes accrued interest.

Investment in North West Redwater Partnership

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

The facility capital cost ("FCC") budget for the Project is currently estimated to be $9,700 million. The Project is currently in the commissioning phase. During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to maintain the agreed debt to equity ratio of 80/20. To December 31, 2018, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $152 million, for a Company total of $591 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 toll, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 17). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at December 31, 2018, the Company had recognized $62 million in prepaid service tolls.

As at December 31, 2018, Redwater Partnership had borrowings of $2,333 million under its secured $3,500 million syndicated credit facility. During the first quarter of 2018, Redwater Partnership extended $2,000 million of the $3,500 million revolving syndicated credit facility to June 2021. The remaining $1,500 million was extended on a fully drawn non-revolving basis maturing February 2020.

During the three months ended December 31, 2018, the Company recognized an equity gain from Redwater Partnership of $nil (three months ended December 31, 2017 – loss of $1 million; year ended December 31, 2018 – loss of $5 million; year ended December 31, 2017 – gain of $31 million).

9. LONG-TERM DEBT

	Dec 31 2018	Dec 31 2017
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 831**	$ 3,544
Medium-term notes	**5,300**	5,300
	6,131	8,844
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2018 - US$2,954 million; December 31, 2017 - US$1,839 million)	**4,031**	2,300
Commercial paper (December 31, 2018 - US$104 million; December 31, 2017 - US$500 million)	**141**	625
US dollar debt securities (December 31, 2018 - US$7,650 million; December 31, 2017 - US$8,650 million)	**10,439**	10,828
	14,611	13,753
Long-term debt before transaction costs and original issue discounts, net	**20,742**	22,597
Less: original issue discounts, net (1)	**17**	18
transaction costs (1) (2)	**102**	121
	20,623	22,458
Less: current portion of commercial paper	**141**	625
current portion of other long-term debt (1) (2)	**1,000**	1,252
	$ 19,482	$ 20,581

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

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

Bank Credit Facilities and Commercial Paper

As at December 31, 2018, the Company had in place revolving bank credit facilities of $4,976 million of which $4,723 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 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 $1,800 million non-revolving term credit facility maturing May 2020;
- a $2,200 million non-revolving term credit facility maturing October 2020;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility with $330 million maturing in June 2019 and $2,095 million maturing June 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022; and
- a £15 million demand credit facility related to the Company’s North Sea operations.

During the second quarter of 2018, the Company extended the $2,425 million revolving syndicated credit facility originally due June 2020 to June 2022. Each of the $2,425 million revolving facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate.

During the year ended December 31, 2018, the Company repaid and cancelled $1,200 million of the $3,000 million non-revolving term credit facility (third quarter of 2018 – $1,050 million; first quarter of 2018 – $150 million) scheduled to mature in May 2020. The required annual amortization of 5% of the original balance is now satisfied. Borrowings under the term loan facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $1,800 million facility was fully drawn.

During the second quarter of 2018, the Company extended the $2,200 million non-revolving credit facility originally due October 2019 to October 2020. Borrowings under the $2,200 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $2,200 million facility was fully drawn.

During the first quarter of 2018, the Company repaid and cancelled the $125 million non-revolving term credit facility scheduled to mature in February 2019. The Company also extended the $750 million non-revolving term credit facility originally due February 2019 to February 2021. Borrowings under the $750 million non-revolving credit facility may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2018, the $750 million facility was fully drawn.

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2018 was 2.6% (December 31, 2017 – 2.2%), and on total long-term debt outstanding for the year ended December 31, 2018 was 3.9% (December 31, 2017 – 3.8%).

As at December 31, 2018, letters of credit and guarantees aggregating to $450 million were outstanding.

Medium-Term Notes

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

US Dollar Debt Securities

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

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

10. OTHER LONG-TERM LIABILITIES

	Dec 31 2018	Dec 31 2017
Asset retirement obligations	**$ 3,886**	$ 4,327
Share-based compensation	**124**	414
Risk management (note 16)	**17**	103
Deferred purchase consideration (1) (2)	**118**	469
Other	**80**	96
	4,225	5,409
Less: current portion	**335**	1,012
	$ 3,890	$ 4,397

(1) Includes $118 million of deferred purchase consideration at December 31, 2018, payable in annual installments of $25 million over the next five years.

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

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 5.0% (December 31, 2017 – 4.7%) and inflation rates of up to 2% (December 31, 2017 - up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2018	Dec 31 2017
Balance – beginning of year	**$ 4,327**	$ 3,243
Liabilities incurred	**19**	12
Liabilities acquired, net	**6**	784
Liabilities settled	**(290)**	(274)
Asset retirement obligation accretion	**186**	164
Revision of cost, inflation rates and timing estimates	**(111)**	(40)
Change in discount rate	**(334)**	509
Foreign exchange adjustments	**83**	(71)
Balance – end of year	**3,886**	4,327
Less: current portion	**186**	92
	$ 3,700	$ 4,235

Share-Based Compensation

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

	Dec 31 2018	Dec 31 2017
Balance – beginning of year	**$ 414**	$ 426
Share-based compensation (recovery) expense	**(146)**	134
Cash payment for stock options surrendered	**(5)**	(6)
Transferred to common shares	**(120)**	(154)
(Recovered from) charged to Oil Sands Mining and Upgrading, net	**(19)**	14
Balance – end of year	**124**	414
Less: current portion	**92**	348
	$ 32	$ 66

Included within share-based compensation liability as at December 31, 2018 was $13 million related to performance share units granted to certain executive employees (December 31, 2017 - $5 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2018**	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Current corporate income tax – North America	**$ (254)**	$ (93)	**$ 312**	$ (145)
Current corporate income tax – North Sea	**8**	10	**28**	57
Current corporate income tax – Offshore Africa	**11**	17	**54**	45
Current PRT (1) – North Sea	**—**	(25)	**(29)**	(132)
Other taxes	**1**	3	**9**	11
Current income tax	**(234)**	(88)	**374**	(164)
Deferred corporate income tax	**112**	307	**540**	586
Deferred PRT (1) – North Sea	**(1)**	(13)	**17**	54
Deferred income tax	**111**	294	**557**	640
Income tax	**$ (123)**	$ 206	**$ 931**	$ 476

(1) Petroleum Revenue Tax.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2018	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of year	**1,222,769**	**$ 9,109**
Issued upon exercise of stock options	**9,975**	**332**
Previously recognized liability on stock options exercised for common shares	**—**	**120**
Purchase of common shares under Normal Course Issuer Bid	**(30,858)**	**(238)**
Balance – end of year	**1,201,886**	**$ 9,323**

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. The dividend is payable on April 1, 2019.

Normal Course Issuer Bid

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

For the year ended December 31, 2018, the Company purchased 30,857,727 common shares at a weighted average price of $41.56 per common share for a total cost of $1,282 million. Retained earnings were reduced by $1,044 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2018, the Company purchased 4,340,000 common shares at a weighted average price of $35.86 per common share for a total cost of $156 million.

Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2018:

	Year Ended Dec 31, 2018		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**56,036**	**$**	**36.67**
Granted	**4,256**	**$**	**43.75**
Surrendered for cash settlement	**(392)**	**$**	**33.46**
Exercised for common shares	**(9,975)**	**$**	**33.28**
Forfeited	**(3,240)**	**$**	**38.76**
Outstanding – end of year	**46,685**	**$**	**37.92**
Exercisable – end of year	**19,436**	**$**	**36.03**

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

13. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Dec 31 2018		Dec 31 2017
Derivative financial instruments designated as cash flow hedges	**$**	**13**	$	47
Foreign currency translation adjustment		**109**		(115)
	$	**122**	$	(68)

14. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At December 31, 2018, 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.

		Dec 31 2018		Dec 31 2017
Long-term debt, net (1)	**$**	**20,522**	$	22,321
Total shareholders' equity	**$**	**31,974**	$	31,653
Debt to book capitalization		**39.1%**		41.4%

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

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2018, the Company was in compliance with this covenant.

15. NET EARNINGS (LOSS) PER COMMON SHARE

		Three Months Ended		Year Ended	
		Dec 31 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Weighted average common shares outstanding – basic (thousands of shares)		**1,204,998**	1,219,865	**1,218,798**	1,175,094
Effect of dilutive stock options (thousands of shares)		**—**	8,547	**4,960**	7,729
Weighted average common shares outstanding – diluted (thousands of shares)		**1,204,998**	1,228,412	**1,223,758**	1,182,823
Net earnings (loss)		**$ (776)**	$ 396	**$ 2,591**	$ 2,397
Net earnings (loss) per common share	– basic	**$ (0.64)**	$ 0.32	**$ 2.13**	$ 2.04
	– diluted	**$ (0.64)**	$ 0.32	**$ 2.12**	$ 2.03

16. FINANCIAL INSTRUMENTS

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

	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)**

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

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

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

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

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

	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)**	**$ —**	**$ —**

	Dec 31, 2017			
	Carrying amount	Fair value		
Asset (liability) [1] [2]		Level 1	Level 2	Level 3 [5]
Investments [3]	$ 893	$ 893	$ —	$ —
Other long-term assets	$ 714	$ —	$ 204	$ 510
Other long-term liabilities	$ (103)	$ —	$ (103)	$ —
Fixed rate long-term debt [6] [7]	$ (15,989)	$ (17,259)	$ —	$ —

(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 paid to Marathon in March 2018).

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

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

(4) The fair value of the deferred purchase consideration 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)		**Dec 31 2018**		Dec 31 2017
Derivatives held for trading				
Foreign currency forward contracts	**$**	**8**	$	(38)
Crude oil WCS [1] differential swaps		**(17)**		—
Natural gas AECO basis swaps		**1**		—
Natural gas AECO fixed price swaps		**3**		—
Cash flow hedges				
Foreign currency forward contracts		**70**		(71)
Cross currency swaps		**291**		210
	$	**356**	$	101
Included within:				
Current portion of other long-term assets	**$**	**92**	$	—
Current portion of other long-term liabilities		**(17)**		(103)
Other long-term assets		**281**		204
	$	**356**	$	101

(1) Western Canadian Select

For the year ended December 31, 2018, the Company recognized a gain of $2 million (year ended December 31, 2017 – gain of $5 million) related to ineffectiveness arising from cash flow hedges.

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

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)		**Dec 31 2018**		Dec 31 2017
Balance – beginning of year	**$**	**101**	$	489
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**35**		(37)
Foreign exchange		**260**		(375)
Other comprehensive (loss) income		**(40)**		24
Balance – end of year		**356**		101
Less: current portion		**75**		(103)
	$	**281**	$	204

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

	Three Months Ended		Year Ended	
	Dec 31 2018	Dec 31 2017	**Dec 31 2018**	Dec 31 2017
Net realized risk management gain	**$ (45)**	$ (73)	**$ (99)**	$ (2)
Net unrealized risk management loss (gain)	**27**	75	**(35)**	37
	$ (18)	$ 2	**$ (134)**	$ 35

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 December 31, 2018, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term	Volume	Weighted average price	Index
Crude Oil				
WCS differential swaps	Jan 2019 - Mar 2019	28,000 bbl/d	US$17.65	WCS
WCS differential swaps	Jan 2019 - Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas				
AECO basis swaps	Jan 2019 - Mar 2019	10,000 MMbtu/d	US$1.39	AECO
AECO fixed price swaps	Jan 2019 - Mar 2019	30,000 GJ/d	$2.30	AECO
AECO fixed price swaps (1)	Apr 2019 - Oct 2019	10,000 GJ/d	$1.30	AECO

(1) Subsequent to December 31, 2018, the Company has hedged an additional 105,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps, at a weighted average price of $1.32/GJ, for April to October 2019.

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 December 31, 2018, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At December 31, 2018, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2019	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2019	—	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2018 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2018, the Company had US$3,506 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,058 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 December 31, 2018, substantially all of the Company's accounts receivable were due within normal trade terms and the average expected credit loss was approximately 1% of the Company's accounts receivable balance.

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 December 31, 2018, the Company had net risk management assets of $361 million with specific counterparties related to derivative financial instruments (December 31, 2017 – $187 million).

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

c) Liquidity risk

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

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

The maturity dates 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	$ 779	$ —	$ —	$ —
Accrued liabilities	$ 2,356	$ —	$ —	$ —
Other long-term liabilities	$ 42	$ 24	$ 69	$ —
Long-term debt (1) (2)	$ 1,141	$ 5,996	$ 3,812	$ 9,793

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

(2) In addition to the financial liabilities disclosed above, estimated interest and other financing payments are as follows: less than one year, $836 million; one to less than two years, $755 million; two to less than five years, $1,668 million; and thereafter, $5,327 million. Interest payments were estimated based upon applicable interest and foreign exchange rates at December 31, 2018.

17. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows:

	2019	2020	2021	2022	2023	Thereafter
Product transportation and pipeline	$ 692	$ 664	$ 620	$ 516	$ 381	$ 3,991
North West Redwater Partnership service toll (1)	$ 86	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore equipment operating leases	$ 94	$ 73	$ 75	$ 8	$ —	$ —
Office leases	$ 42	$ 42	$ 39	$ 31	$ 32	$ 89
Other	$ 85	$ 35	$ 32	$ 32	$ 31	$ 424

(1) 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 service toll is $1,301 million of interest payable over the 30 year tolling period. See note 8.

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

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

18. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**923**	2,265	**7,254**	7,655	**218**	182	**753**	666	**204**	170	**628**	579	**1,345**	2,617	**8,635**	8,900
Natural gas	**422**	327	**1,256**	1,506	**28**	33	**140**	118	**17**	14	**70**	53	**467**	374	**1,466**	1,677
Total segmented product sales	**1,345**	2,592	**8,510**	9,161	**246**	215	**893**	784	**221**	184	**698**	632	**1,812**	2,991	**10,101**	10,577
Less: royalties	**(38)**	(228)	**(723)**	(809)	**(1)**	—	**(2)**	(1)	**(9)**	(16)	**(51)**	(41)	**(48)**	(244)	**(776)**	(851)
Segmented revenue	**1,307**	2,364	**7,787**	8,352	**245**	215	**891**	783	**212**	168	**647**	591	**1,764**	2,747	**9,325**	9,726
Segmented expenses																
Production	**589**	632	**2,405**	2,362	**134**	119	**405**	400	**87**	46	**208**	226	**810**	797	**3,018**	2,988
Transportation, blending and feedstock	**541**	665	**2,587**	2,291	**4**	5	**22**	31	**1**	—	**2**	1	**546**	670	**2,611**	2,323
Depletion, depreciation and amortization	**779**	850	**3,132**	3,243	**88**	37	**257**	509	**62**	52	**201**	205	**929**	939	**3,590**	3,957
Asset retirement obligation accretion	**21**	21	**87**	80	**8**	6	**29**	27	**2**	3	**9**	9	**31**	30	**125**	116
Risk management activities (commodity derivatives)	**9**	7	**(10)**	(45)	**—**	—	**—**	—	**—**	—	**—**	—	**9**	7	**(10)**	(45)
Gain on acquisition, disposition and revaluation of properties	**(5)**	—	**(277)**	(35)	**—**	—	**(139)**	—	**(36)**	—	**(36)**	—	**(41)**	—	**(452)**	(35)
Equity loss (gain) from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**1,934**	2,175	**7,924**	7,896	**234**	167	**574**	967	**116**	101	**384**	441	**2,284**	2,443	**8,882**	9,304
Segmented earnings (loss) before the following	**(627)**	189	**(137)**	456	**11**	48	**317**	(184)	**96**	67	**263**	150	**(520)**	304	**443**	422
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange loss (gain)																
Loss (gain) from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax expense																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream				Inter–segment elimination and other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2018	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Segmented product sales																
Crude oil and NGLs	**1,838**	2,323	**11,521**	7,072	**24**	28	**102**	102	**120**	130	**410**	448	**3,327**	5,098	**20,668**	16,522
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**37**	44	**148**	161	**504**	418	**1,614**	1,838
Total segmented product sales	**1,838**	2,323	**11,521**	7,072	**24**	28	**102**	102	**157**	174	**558**	609	**3,831**	5,516	**22,282**	18,360
Less: royalties	**(81)**	(69)	**(479)**	(167)	**—**	—	**—**	—	**—**	—	**—**	—	**(129)**	(313)	**(1,255)**	(1,018)
Segmented revenue	**1,757**	2,254	**11,042**	6,905	**24**	28	**102**	102	**157**	174	**558**	609	**3,702**	5,203	**21,027**	17,342
Segmented expenses																
Production	**797**	846	**3,367**	2,600	**5**	4	**21**	16	**15**	17	**58**	71	**1,627**	1,664	**6,464**	5,675
Transportation, blending and feedstock	**174**	339	**1,087**	679	**—**	—	**—**	—	**144**	152	**491**	527	**864**	1,161	**4,189**	3,529
Depletion, depreciation and amortization	**396**	464	**1,557**	1,220	**3**	3	**14**	9	**—**	—	**—**	—	**1,328**	1,406	**5,161**	5,186
Asset retirement obligation accretion	**15**	15	**61**	48	**—**	—	**—**	—	**—**	—	**—**	—	**46**	45	**186**	164
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**9**	7	**(10)**	(45)
Gain on acquisition, disposition and revaluation of properties	**—**	—	**—**	(230)	**—**	—	**—**	(114)	**—**	—	**—**	—	**(41)**	—	**(452)**	(379)
Equity loss (gain) from investments	**—**	—	**—**	—	**—**	1	**5**	(31)	**—**	—	**—**	—	**—**	1	**5**	(31)
Total segmented expenses	**1,382**	1,664	**6,072**	4,317	**8**	8	**40**	(120)	**159**	169	**549**	598	**3,833**	4,284	**15,543**	14,099
Segmented earnings (loss) before the following	**375**	590	**4,970**	2,588	**16**	20	**62**	222	**(2)**	5	**9**	11	**(131)**	919	**5,484**	3,243
Non–segmented expenses																
Administration													**91**	84	**325**	319
Share-based compensation													**(148)**	97	**(146)**	134
Interest and other financing expense													**179**	169	**739**	631
Risk management activities (other)													**(27)**	(5)	**(124)**	80
Foreign exchange loss (gain)													**546**	(17)	**827**	(787)
Loss (gain) from investments													**127**	(11)	**341**	(7)
Total non–segmented expenses													**768**	317	**1,962**	370
Earnings (loss) before taxes													**(899)**	602	**3,522**	2,873
Current income tax (recovery) expense													**(234)**	(88)	**374**	(164)
Deferred income tax expense													**111**	294	**557**	640
Net earnings (loss)													**(776)**	396	**2,591**	2,397

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2018			Dec 31, 2017		
	Net expenditures	**Non-cash and fair value changes**	**Capitalized costs**	Net expenditures [2]	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 118**	**$ (52)**	**$ 66**	$ 160	$ (184)	$ (24)
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa [4]	**(54)**	**—**	**(54)**	15	—	15
Oil Sands Mining and Upgrading	**218**	**(225)**	**(7)**	142	117	259
	$ 282	**$ (277)**	**$ 5**	$ 317	$ (67)	$ 250
Property, plant and equipment						
Exploration and Production						
North America	**$ 2,553**	**$ (362)**	**$ 2,191**	$ 2,815	$ 354	$ 3,169
North Sea	**131**	**(597)**	**(466)**	160	95	255
Offshore Africa	**228**	**(86)**	**142**	89	12	101
	2,912	**(1,045)**	**1,867**	3,064	461	3,525
Oil Sands Mining and Upgrading [5]	**1,229**	**(166)**	**1,063**	9,592	5,454	15,046
Midstream [6]	**13**	**—**	**13**	80	114	194
Head office	**21**	**—**	**21**	19	—	19
	$ 4,175	**$ (1,211)**	**$ 2,964**	$ 12,755	$ 6,029	$ 18,784

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

(2) Net expenditures on exploration and evaluation assets and property, plant and equipment for the year ended December 31, 2017 exclude non-cash share consideration of $3,818 million issued on the acquisition of AOSP and other assets. This non-cash consideration is included in non-cash and other fair value changes.

(3) The above noted figures for 2017 exclude the impact of a pre-tax cash gain of $35 million on the disposition of certain exploration and evaluation assets.

(4) The above noted figures for 2018 exclude the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets.

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

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

Segmented Assets

	Dec 31 2018	Dec 31 2017
Exploration and Production		
North America	**$ 27,199**	$ 28,705
North Sea	**1,699**	1,854
Offshore Africa	**1,471**	1,331
Other	**33**	29
Oil Sands Mining and Upgrading	**39,634**	40,559
Midstream	**1,413**	1,279
Head office	**110**	110
	$ 71,559	$ 73,867

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios for the twelve month period ended December 31, 2018:	
Interest coverage (times)	
Net earnings [(1)]	5.3x
Adjusted funds flow [(2)]	12.6x

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

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

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Corporate Information

Board of Directors

Catherine M. Best, FCA, ICD.D

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

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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

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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

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Senior Vice-President, Development Operations

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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

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