Canadian Natural

FOURTH QUARTER REPORT

YEAR ENDED DECEMBER 31, 2019 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2019 FOURTH QUARTER AND YEAR END RESULTS

Commenting on the Company's 2019 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "2019 marked the 30th anniversary of Canadian Natural as an Exploration and Production ("E&P") company. Over the past 3 decades, our unwavering focus on returns and free cash flow generating assets has driven significant growth and high returns for our shareholders. Today, we are set up better than ever with a large, diversified portfolio underpinned by long life low decline assets that generate significant and sustainable free cash flow throughout the business cycles."

Canadian Natural's President, Tim McKay, added, "In 2019, we demonstrated that Canadian Natural is truly a unique, sustainable and robust company. Our unparalleled asset base underpinned by our long life low decline assets combined with our E&P assets generated record adjusted funds flow of approximately $10.3 billion and delivered record free cash flow of approximately $4.6 billion in 2019, excluding major acquisition costs. The Company achieved record production totaling 1,098,957 BOE/d, delivering 2% production growth over 2018 levels in a curtailed environment. Production per share growth in Q4/19 over Q4/18 levels was significant at 8% per share.

Canadian Natural's strong team of employees and corporate culture of leveraging technology, innovation and continuous improvement drove significant value growth as the Company captured approximately $550 million of annual incremental margins in 2019. The Company's continued focus on delivering margin growth through effective and efficient operations and cost control resulted in annual E&P operating costs decreasing by 10% from 2018 levels to $11.49/BOE. The Company continues to capture margin growth opportunities across our entire asset base delivering significant and sustainable free cash flow in 2020 and beyond.

In 2019, Canadian Natural continued its strong track record of delivering excellent finding, development and acquisition ("FD&A") costs and reserves replacement ratios, reflecting the strength of our mix of long life low decline assets and effective and efficient operations. Company Gross proved reserves increased 11% to 10.993 billion BOE, replacing 2019 production by 374% with a reserves life index of 27.8 years. Proved FD&A costs, including changes in future development costs, were $7.45/BOE.

Due to the volatile state of the current crude oil price environment, Canadian Natural has reduced its 2020 Oil Sands Mining and Upgrading capital budget by approximately $100 million, demonstrating the Company’s flexibility and ability to be nimble. This reduction will have no impact on 2020 production volumes. Total corporate capital expenditures in 2020 are now targeted to be $3,950 million."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, continued, "Throughout 2019, Canadian Natural's financial strength was once again displayed by maintaining a strong balance sheet while maximizing financial flexibility. In 2019, the Company achieved record net earnings of approximately $5.4 billion and adjusted net earnings of approximately $3.8 billion. At December 31, 2019 long-term debt totaled $20,982 million, comparable to Q1/19 levels prior to the Devon Canada asset acquisition, and debt to book capitalization strengthened to 37.3% from 39.1% at year end 2018 while debt to adjusted EBITDA improved to 1.9x from 2.0x at year end 2018. Returns to shareholders were significant, returning over $2.6 billion to shareholders through dividends of approximately $1.7 billion and share repurchases of approximately $0.9 billion. Looking forward to 2020, as we continue to deliver on our financial plan, our defined free cash flow allocation policy targets to further strengthen our balance sheet along with increasing returns to our shareholders.

Subsequent to year end, the Company's Board of Directors approved a quarterly dividend increase of 13% to $0.425 per share payable on April 1, 2020. The increase marks the 20th consecutive year of dividend increases, and reflects the Board of Directors' confidence in the strength and robustness of our assets and our ability to generate significant and sustainable free cash flow."

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
Net earnings	**$ 597**	$ 1,027	$ (776)	**$ 5,416**	$ 2,591
Per common share – basic	**$ 0.50**	$ 0.87	$ (0.64)	**$ 4.55**	$ 2.13
– diluted	**$ 0.50**	$ 0.87	$ (0.64)	**$ 4.54**	$ 2.12
Adjusted net earnings from operations (1)	**$ 686**	$ 1,229	$ (255)	**$ 3,795**	$ 3,263
Per common share – basic	**$ 0.58**	$ 1.04	$ (0.21)	**$ 3.19**	$ 2.68
– diluted	**$ 0.58**	$ 1.04	$ (0.21)	**$ 3.18**	$ 2.67
Cash flows from operating activities	**$ 2,454**	$ 2,518	$ 1,397	**$ 8,829**	$ 10,121
Adjusted funds flow (2)	**$ 2,494**	$ 2,881	$ 1,229	**$ 10,267**	$ 9,088
Per common share – basic	**$ 2.11**	$ 2.43	$ 1.02	**$ 8.62**	$ 7.46
– diluted	**$ 2.10**	$ 2.43	$ 1.02	**$ 8.61**	$ 7.43
Cash flows used in investing activities	**$ 854**	$ 908	$ 1,042	**$ 7,255**	$ 4,814
Net capital expenditures, excluding Devon Canada asset acquisition costs (3)	**$ 1,056**	$ 963	$ 1,181	**$ 3,904**	$ 4,731
Total net capital expenditures, including Devon Canada asset acquisition costs (3)	**$ 1,056**	$ 963	$ 1,181	**$ 7,121**	$ 4,731
Daily production, before royalties					
Natural gas (MMcf/d)	**1,455**	1,469	1,488	**1,491**	1,548
Crude oil and NGLs (bbl/d)	**913,782**	931,546	833,358	**850,393**	820,778
Equivalent production (BOE/d) (4)	**1,156,276**	1,176,361	1,081,368	**1,098,957**	1,078,813

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

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

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

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

ANNUAL HIGHLIGHTS

- Net earnings of $5,416 million were realized in 2019, while adjusted net earnings of $3,795 million were achieved in 2019, a $532 million increase over 2018 levels.
- Cash flows from operating activities were $8,829 million in 2019, a decrease of $1,292 million compared to 2018 levels primarily due to the impact of changes in non-cash working capital.
- Canadian Natural generated record annual adjusted funds flow of $10,267 million in 2019, an increase of 13% or $1,179 million over 2018 levels. The increase over 2018 was primarily due to higher crude oil and NGL netbacks in the Company's Exploration and Production ("E&P") segment and higher volumes in the Company's thermal in situ and international areas.

- Cash flows used in investing activities were $7,255 million in 2019, an increase of $2,441 million compared to 2018 levels as a result of the Devon Canada asset acquisition completed in 2019, partially offset by lower capital expenditures in the year.
- Canadian Natural delivered record annual free cash flow of $4,620 million after net capital expenditures of $3,904 million and dividend requirements of $1,743 million, and excluding Devon Canada asset acquisition costs, reflecting the strength of the Company's long life low decline asset base and effective and efficient operations.
  - Balance sheet strength remains a focus as year end 2019 long-term debt totaled $20,982 million, comparable to Q1/19 levels prior to the Devon Canada asset acquisition, and debt to book capitalization strengthened to 37.3% from 39.1% at year end 2018 while debt to adjusted EBITDA improved to 1.9x from 2.0x at year end 2018. During 2019, the Company executed on the following:
    - The Company repaid $500 million of 3.05% notes and $500 million of 2.60% notes in Q2/19 and Q4/19, respectively.
    - The Company fully repaid and canceled the remaining balance of the $1,800 million non-revolving term loan credit facility that was used to finance the Athabasca Oil Sands Project ("AOSP") acquisition, ahead of its maturity in May 2020.
    - Additionally, the $2,200 million non-revolving term credit facility, originally due in October 2020, was extended to February 2023 and increased by $450 million to $2,650 million.
  - Canadian Natural is committed to returns to shareholders, returning a total of $2,684 million to shareholders in 2019, $1,743 million by way of dividends and $941 million by way of share repurchases.
    - Share repurchases for cancellation totaled 25,900,000 common shares at a weighted average share price of $36.32.
    - Subsequent to year end, up to and including March 4, 2020, the Company executed on additional share repurchases for cancellation of 6,600,000 common shares at a weighted average share price of $39.41.
    - Returns to shareholders have been significant as Canadian Natural returned approximately $6.2 billion by way of dividends and share repurchases between January 1, 2018 and March 4, 2020.
    - 2019 dividends increased 12% from 2018 levels to $1.50 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 13% to $0.425 per share, payable on April 1, 2020. The increase marks the 20th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's strength and robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
- Canadian Natural's strong team of employees and corporate culture of leveraging technology, innovation and continuous improvement drove significant value growth as the Company captured approximately $550 million of annual incremental margin in 2019, some of the key achievements are identified as follows:
  - Canadian Natural's continued focus on delivering margin growth through effective and efficient operations, execution on the Company's curtailment optimization strategy and cost control was demonstrated as the Company's E&P annual operating costs were $11.49/BOE in 2019, representing a 10% decrease or approximately $310 million of margin improvement from 2018 levels.
    - Pelican Lake annual operating costs decreased by 7% to $6.22/bbl from 2018 levels.
    - Thermal in situ annual operating costs decreased by 18% to $10.83/bbl from 2018 levels.
    - North America natural gas annual operating costs decreased by 7% to $1.16/Mcf from 2018 levels.
  - Oil Sands Mining and Upgrading annual operating costs, excluding energy costs, decreased $91 million or 3% from 2018 levels.
  - As part of Canadian Natural's natural gas marketing strategy, the Company has continued to diversify its natural gas sales points, equating to approximately $115 million of additional margin in 2019.
- The Company has identified approximately $900 million of additional annual margin growth opportunities of which approximately $180 million are targeted to be captured in 2020.
- The Company achieved record annual production volumes of 1,098,957 BOE/d in 2019, an increase of 2% over 2018 levels, primarily due to production from the acquisition of thermal in situ and primary heavy crude oil assets from Devon Canada and execution of the Company's curtailment optimization strategy, offsetting the impact of a proactive

piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year.

- Production per share growth was significant at approximately 8% from Q4/18 to Q4/19, as a result of accretive acquisitions, effective and efficient operations and execution on the Company's free cash flow allocation policy.
- The Company achieved record annual liquids production volumes of 850,393 bbl/d in 2019, an increase of 4% over 2018 levels.

▪ The Company continues to execute operational flexibility through its curtailment optimization strategy as follows:
  - Increasing crude oil production from the Company's balanced asset base to mitigate production impacts during periods of planned and unplanned downtime.
  - Modified timing of the Company's planned turnaround activities to target its monthly curtailment allowable production volumes.
  - Maximizing value through production optimization of higher netback assets.
  - Allowing the Company to execute on proactive maintenance activities to enhance long-term reliability.

▪ Thermal in situ oil sands production volumes were strong in 2019, averaging a record 167,942 bbl/d, a 56% increase over 2018 levels, primarily as a result of the Jackfish acquisition and increased production from Kirby North and pad additions at Primrose, reflecting the successful execution of the Company's curtailment optimization strategy.
  - At Kirby North, production ramp up continues to be strong, exceeding expectations as a result of top tier execution and productivity, with a December 2019 exit rate of approximately 26,500 bbl/d. As a result of improved well design, high plant reliability and effective and efficient operations, the project now targets to reach peak overall capacity of 40,000 bbl/d in early Q3/20, ahead of schedule, driving additional margins in 2020.
  - High return, drill to fill pad additions at Primrose came on ahead of schedule and on budget with strong production averaging approximately 32,000 bbl/d in Q4/19. As previously announced, these pad additions are targeted to add approximately 26,000 bbl/d in the first 12 months of production.
  - At Jackfish, the Company successfully completed tie in activities in Q4/19 on the previously drilled pad additions that have production capability of 21,000 bbl/d for minimal capital of approximately $8 million. Production from these pads is targeted to reach overall peak production in early 2022 and is targeted to offset conventional production declines with long life low decline thermal in situ production as the Company manages within its curtailment optimization strategy.

▪ At the Company's world class Oil Sands Mining and Upgrading assets, annual production volumes averaged 395,133 bbl/d of Synthetic Crude Oil ("SCO") in 2019, a decrease of 7% from 2018 levels, reflecting the proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year.
  - At AOSP, through increased reliability, process improvements and optimization projects, Canadian Natural increased gross production capacity at the Albian mines by approximately 40,000 bbl/d to approximately 320,000 bbl/d, representing a 14% increase in capacity while reducing AOSP operating costs by approximately 34% or $10.00/bbl since the announcement of the acquisition in 2017.
  - As part of the Company's overall strategy to maximize value and enhance margins, the Scotford Upgrader is targeting to increase capacity to approximately 320,000 bbl/d in Q3/20. This additional capacity at AOSP will allow for increased flexibility, margin improvements and can be managed through the Company's curtailment optimization strategy.

▪ International E&P crude oil production volumes were strong in 2019, averaging 49,290 bbl/d, an increase of 13% over 2018 levels. The increase over 2018 was primarily due to strong performance from wells drilled in the North Sea and at Baobab, partially offset by natural field declines.

▪ The Company now targets approximately $190 million in annual operating costs savings from assets acquired from Devon Canada, $55 million in excess of its initially identified targeted annual operating cost savings of $135 million.

▪ Due to the volatile state of the current crude oil price environment, Canadian Natural has reduced its 2020 Oil Sands Mining and Upgrading capital budget by approximately $100 million, demonstrating the Company’s flexibility and ability to be nimble. This reduction will have no impact on 2020 production volumes. Total corporate capital expenditures in 2020 are now targeted to be $3,950 million.

- In Q2/19, the Government of Alberta enacted a series of tax rate reductions which will decrease the provincial corporate income tax rate from 12% to 8% by 2022. As a result of this reduction, Canadian Natural estimates current tax savings of approximately $15 million in 2019 and approximately $30 million in 2020. As previously disclosed, these current tax savings coupled with the elimination of curtailment for certain conventional drilling in Alberta resulted in the Company increasing its 2020 E&P capital budget by approximately $250 million over 2019 levels, targeting 60 additional drilling locations across Alberta.
  - In accordance with International Financial Reporting Standards, the Company recorded a non-cash accounting reduction in its deferred tax liability of $1,618 million in Q2/19. Over the next several decades, the Company is expected to continue to realize current tax savings resulting from the tax rate reductions.

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, 2019 (all reserves values are Company Gross unless stated otherwise).
  - Canadian Natural’s 2019 performance has resulted in another year of excellent finding and development costs:
    - Finding, Development and Acquisition ("FD&A") costs, excluding changes in Future Development Costs ("FDC"), are $4.52/BOE for proved reserves and $5.34/BOE for proved plus probable reserves.
    - FD&A costs, including changes in FDC, are $7.45/BOE for proved reserves and $5.75/BOE for proved plus probable reserves.
  - Proved reserves increased 11% to 10.993 billion BOE with reserves additions and revisions of 1.501 billion BOE. Proved plus probable reserves increased 6% to 14.252 billion BOE with reserves additions and revisions of 1.271 billion BOE.
  - Proved reserves additions and revisions replaced 2019 production by 374%. Proved plus probable reserves additions and revisions replaced 2019 production by 317%.
  - The proved BOE reserves life index is 27.8 years and the proved plus probable BOE reserves life index is 36.0 years.
  - Proved developed producing reserves additions and revisions are 0.778 billion BOE, replacing 2019 production by 194%. The total proved developed producing BOE reserves life index is 20.2 years.
  - The net present value of future net revenues, before income tax, discounted at 10%, increased 1% to $107.6 billion for proved reserves and decreased 2% to $127.8 billion for proved plus probable reserves. The net present value for proved developed producing reserves is relatively unchanged at $84.3 billion.

MARKETING UPDATE

- Mainline enhancements of approximately 100,000 bbl/d of capacity were completed in December 2019, increasing pipeline capacity out of the Western Canadian Sedimentary Basin ("WCSB").
- Additional pipeline egress of approximately 190,000 bbl/d to move incremental crude oil production out of the WCSB is targeted to be added by industry over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Additional Mainline enhancements of 50,000 bbl/d of capacity are targeted in 2020.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in 2020.
  - The North West Redwater Refinery ("NWR") is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up of the Gasifier and LC Finer units, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available in 2020.
- Crude by rail volumes continue to be strong at approximately 350,000 bbl/d for the month of December 2019.

ENVIRONMENTAL HIGHLIGHTS

- Canadian Natural is committed to achieving its aspirational goal of net zero Oil Sands emissions through its leading environmental performance and technology, innovation and continuous improvement potential pathways, which are listed on the Company's website at https://www.cnrl.com/corporate-responsibility/advancements-in-technology/.
- As part of Canadian Natural's commitment to its aspirational goal of net zero Oil Sands emissions, the Company announced the following environmental targets at its Investor Day in December 2019:
  - Reduction of Oil Sands greenhouse gas ("GHG") emissions intensity by 25% by 2025, from a 2016 baseline.
  - Reduction of methane emissions in its North America E&P operations by 20% by 2025, from a 2016 baseline.
  - Reduction in water intensity in its in situ operations by 50% by 2022, from a 2012 baseline.
  - Reduction of Oil Sands mining fresh river water intensity by 30% by 2022, from a 2012 baseline.
- At the end of 2019, highlights from the Company's environmental performance are as follows:
  - As part of Canadian Natural's industry leading reclamation and proactive liability management program, the Company achieved the following reclamation success in 2019:
    - In the Company's North America E&P segment, Canadian Natural proactively abandoned 2,035 wells, an increase of 57% over 2018 levels, as well as submitted 912 reclamation certificate applications and received 893 reclamation certificates during the year.
      - In Alberta, Canadian Natural received 850 reclamation certificates which is the largest number of certificates received by an operator and represents 18% of the total certificates issued.
    - The Company reclaimed 3,118 hectares of land in 2019 in the Company's North America E&P segment, a 125% increase over 2018 levels.
  - In the Oil Sands Mining and Upgrading segment, water use intensity decreased in 2019 by 17% from 2018 levels.
  - The Company reduced its fresh water usage by 28%, sourcing approximately 82% from recycled produced water at Primrose in 2019.
- The Company confirms that 100% of direct emissions from its Alberta Oil Sands in situ and mining operations were third party verified in 2018 and the verification process is underway for 2019 emissions. The verification is completed by a third party professional engineering firm.
- Canadian Natural has invested approximately $3.4 billion in research and development from 2009 to 2018 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, making the Company one of the largest CO_2 capturers and sequesterers for the oil and natural gas sector globally. 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 in the NWR refinery when on stream. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year.
- Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by projects described in its Creating Value through Technology and Innovation Case Studies published in December 2019, which is available on the Company's website at https://www.cnrl.com/upload/media_element/1279/05/technology-and-innovation-case-studies-web.pdf. Highlights from the publication are as follows:
  - The In Pit Extraction Process ("IPEP") pilot at Horizon will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's bitumen production GHG emissions by approximately 40% and lower the Company's environmental footprint by decreased material handling, reducing the distance driven by its fleet of haul trucks, decreasing the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to reduce capital and operating costs.
    - Results from the initial testing phase for the Company's IPEP pilot have been positive, with excellent recovery rates and evidence of stackable tailings. The Company is implementing enhancements to improve overall operability in 2020.

- Solvent Enhanced Oil Recovery technology is being tested at the Company's in situ operations to increase crude oil recovery, reduce steam-to-oil ratios ("SOR") by up to 50%, translating into GHG intensity reduction of up to 50%. To date, the Company has seen increases in crude oil production, lower SOR and high solvent recovery at its Kirby South operations. In addition, the Company is planning commercial scale demonstration tests to verify economics and execution details are being refined through 2020. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
- Methane emission reduction projects will reduce the Company's emissions through focusing on operational practices and innovative technologies. Through the Company's pneumatic retrofit program which began in 2018, the Company reduced approximately 400,000 tonnes of CO_2 equivalent per year by completing approximately 4,000 controller retrofits by the end of 2019. In 2020, the Company is targeting an additional 1,300 controller retrofits, a reduction of approximately 130,000 tonnes of CO_2 equivalent per year.

FOURTH QUARTER HIGHLIGHTS

- Net earnings of $597 million were realized in Q4/19, while adjusted net earnings of $686 million were achieved in Q4/19, a $543 million decrease from Q3/19 levels.
- Cash flows from operating activities were $2,454 million in Q4/19, a decrease of $64 million compared to Q3/19 levels.
- Canadian Natural generated quarterly adjusted funds flow of $2,494 million in Q4/19, a decrease of 13% or $387 million from Q3/19 levels, primarily due to lower SCO volumes in the Oil Sands Mining and Upgrading segment and lower E&P crude oil and NGL netbacks driven largely by lower crude oil pricing, partially offset by lower E&P operating costs, higher North America crude oil and NGL production volumes and higher natural gas prices.
- Canadian Natural's continued focus on delivering effective and efficient operations and cost control was demonstrated as the Company's E&P Q4/19 operating costs were $10.79/BOE, 3% and 20% reductions from Q3/19 and Q4/18 levels respectively.
- Cash flows used in investing activities were $854 million in Q4/19.
- Canadian Natural delivered strong quarterly free cash flow of $994 million after net capital expenditures of $1,056 million and dividend requirements of $444 million in Q4/19, reflecting the strength of the Company's long life low decline asset base and effective and efficient operations.
  - Balance sheet strength remains a focus as long-term debt decreased by $1,507 million from Q3/19 levels to $20,982 million at December 31, 2019. Debt to book capitalization strengthened to 37.3% from 39.1% and debt to adjusted EBITDA improved to 1.9x from 2.6x quarter over quarter.
    - In Q4/19, Canadian Natural repaid $500 million of 2.60% notes and fully repaid and canceled the $1,000 million remaining balance on the non-revolving term loan credit facility that was used to finance the AOSP acquisition, ahead of its maturity in May 2020.
  - Canadian Natural is committed to returns to shareholders, returning a total of $584 million to shareholders in Q4/19, $444 million by way of dividends and $140 million by way of share repurchases.
- The Company achieved quarterly production volumes of 1,156,276 BOE/d in Q4/19, a 7% increase and 2% decrease from Q4/18 and Q3/19 levels respectively. The increase over Q4/18 primarily reflected production from the acquisition of thermal in situ and primary heavy crude oil assets from Devon Canada, offsetting the impact of the completion of the planned turnaround and a proactive piping replacement at Horizon in Q4/19. The decrease from Q3/19 primarily reflected the proactive piping replacement at Horizon in Q4/19 partially offset by the Company's execution of its curtailment optimization strategy.
  - Canadian Natural's North America E&P crude oil and NGLs production volumes, excluding thermal in situ, averaged 247,184 bbl/d in Q4/19, comparable to Q3/19 and a 3% increase over Q4/18 levels. The increase over Q4/18 was primarily due to production from primary heavy crude oil assets acquired from Devon Canada.
  - Thermal in situ oil sands production volumes were strong in the quarter, averaging a record 259,387 bbl/d, a 26% increase and 154% increase over Q3/19 and Q4/18 levels respectively. The increase over Q3/19, primarily reflected the successful execution of the Company's curtailment optimization strategy as production ramped up from Kirby North and Primrose pad additions and increased production at Jackfish. The increase over Q4/18 primarily reflected production volumes from the Devon Canada asset acquisition, together with new production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base.

    - Thermal in situ operating costs were strong in Q4/19 at $8.65/bbl, reductions of 11% and 35% from Q3/19 and Q4/18 levels respectively, primarily as a result of higher production volumes and synergies captured to date from the Devon Canada asset acquisition, partially offset by higher fuel costs.
- At the Albian mines, top tier operations combined with optimization of facilities resulted in record gross bitumen production averaging approximately 306,000 bbl/d in Q4/19, forming a part of the Company's curtailment optimization strategy during the turnaround and the proactive piping replacement at Horizon.
- In Q4/19 at Horizon, as a result of Canadian Natural's industry leading integrity program, the Company identified the need to replace piping on one of the hydrogen manufacturing units during post turnaround start-up. To ensure increased reliability of operations and as part of the Company's curtailment optimization strategy, the Company made the proactive decision to replace the piping, at which time Horizon ran at restricted rates of approximately 170,500 bbl/d, and production impacts were managed as part of the Company's curtailment optimization strategy. The proactive piping replacement was completed for approximately $65 million and production resumed to full rates on January 19, 2020.
    - Record monthly production of approximately 262,600 bbl/d of SCO was achieved at Horizon in February 2020 as a result of continued high utilization, safe, steady and reliable operations.
- International E&P crude oil production volumes averaged 49,355 bbl/d, in-line with Q3/19 and an increase of 14% over Q4/18 levels. The increase from Q4/18 was primarily as a result of strong volumes from wells drilled at Baobab and in the North Sea.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

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

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

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

Drilling Activity

	Year Ended Dec 31			
	2019		2018	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**96**	**86**	513	483
Natural gas	**30**	**19**	25	18
Dry	**3**	**3**	9	9
Subtotal	**129**	**108**	547	510
Stratigraphic test / service wells	**519**	**447**	717	615
Total	**648**	**555**	1,264	1,125
Success rate (excluding stratigraphic test / service wells)		**97%**		98%

- The Company's total crude oil and natural gas drilling program of 108 net wells for the year ended December 31, 2019, excluding strat/service wells, represents a decrease of 402 net wells from the same period in 2018. The Company's drilling levels primarily reflect the impacts of reduced capital allocation as a result of Alberta curtailments and execution of the Company's curtailment optimization strategy.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs production (bbl/d)	**247,184**	244,267	240,942	**238,028**	243,122
Net wells targeting crude oil	**9**	33	62	**79**	361
Net successful wells drilled	**9**	33	61	**77**	353
Success rate	**100%**	100%	98%	**97%**	98%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ, averaged 238,028 bbl/d in 2019, a 2% decrease from 2018 levels, primarily reflecting natural field declines and the Company's strategic decision to reduce activity due to mandatory production curtailments in Alberta, partially offset by the acquisition of primary heavy crude oil assets from Devon Canada.

- Canadian Natural's primary heavy crude oil production averaged 82,189 bbl/d in 2019, a 5% decrease from 2018 levels as a result of the Company's strategic decision to reduce activity due to mandatory production curtailments in Alberta, partially offset by additional volumes from the Devon Canada asset acquisition.
  - Strong operating costs of $16.66/bbl were achieved in the Company's primary heavy crude oil operations in 2019, comparable to 2018 levels, impressive results given lower production volumes and the Company's continued focus on capturing synergies and margin improvements.
- Pelican Lake annual production averaged 58,855 bbl/d in 2019, a decrease of 7% from 2018 levels, reflecting natural field declines and the Company's strategic decision to reduce activity due to mandatory production curtailments in Alberta.
  - At Pelican Lake, the Company continues to demonstrate effective and efficient operations as annual operating costs decreased by 7% from 2018 levels, averaging $6.22/bbl in 2019, as a result of the Company's focus on cost control. As part of Canadian Natural's margin enhancement opportunities, the Company is targeting to achieve approximately $10 million in incremental cost savings at Pelican Lake in 2020.
- North American light crude oil and NGL production averaged 96,984 bbl/d in 2019, a 3% increase from 2018 levels primarily as a result of the Company's strategic decision to reallocate capital to non-curtailed light crude oil in Saskatchewan and liquids rich natural gas areas, combined with the execution of the Company's curtailment optimization strategy and continued strong production from 2018 and 2019 drilling in the Greater Wembley and Karr areas.
  - In 2019, operating costs were $15.21/bbl in the Company's North America light crude oil and NGL areas, comparable to 2018 levels.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Bitumen production (bbl/d)	**259,387**	206,395	102,112	**167,942**	107,839
Net wells targeting bitumen	**3**	—	41	**3**	125
Net successful wells drilled	**3**	—	40	**3**	124
Success rate	**100%**	—	98%	**100%**	99%

▪ Thermal in situ oil sands production volumes were strong in 2019, averaging a record 167,942 bbl/d, a 56% increase over 2018 levels, primarily as a result of the Jackfish acquisition and increased production from Kirby North and pad additions at Primrose, reflecting the successful execution of the Company's curtailment optimization strategy.

- Thermal in situ operating costs were strong in 2019, a decrease of 18% from 2018 levels, averaging $10.83/bbl, primarily as a result of higher production volumes, synergies captured to date from the Devon Canada asset acquisition and the Company's continued focus on cost control, partially offset by higher energy costs.
- At Primrose, 2019 production volumes averaged 78,606 bbl/d, an increase of 12% over 2018 levels, primarily due to new production from pad additions that came on in late Q3/19, together with execution of the Company's curtailment optimization strategy.
  - High return, drill to fill pad additions at Primrose came on ahead of schedule and on budget with strong production averaging approximately 32,000 bbl/d in Q4/19. As previously announced, these pad additions are targeted to add approximately 26,000 bbl/d in the first 12 months of production.
- At Kirby, which now includes both Kirby South and Kirby North, SAGD production volumes averaged 34,094 bbl/d in 2019, a 3% decrease from 2018 levels due to natural field declines at Kirby South as a result of the Company's capital allocation decisions due to mandatory production curtailments in Alberta, offsetting the ramp up of Kirby North production.
  - At Kirby North, production ramp up continues to be strong, exceeding expectations as a result of top tier execution and productivity, with a December 2019 exit rate of approximately 26,500 bbl/d. As a result of improved well design, high plant reliability and effective and efficient operations, the project now targets to

reach peak overall capacity of 40,000 bbl/d in early Q3/20, ahead of schedule, driving additional margins in 2020.

    ◦ Results from the Company's solvent enhanced SAGD pilot that began in late Q2/19 at Kirby South continue to be positive, indicating that targeted SOR reductions of 30% to 50% remain achievable. If success continues during the two year pilot, learnings from this pilot have the potential for application throughout the Company's extensive thermal in situ asset base, significantly reducing the Company's GHG intensity by up to 50% and at the same time significantly reducing operating costs.

- At Jackfish, SAGD production volumes averaged 102,106 bbl/d in Q4/19, a 5% increase over Q3/19 levels, reflecting execution on the Company's curtailment optimization strategy. The Company has successfully integrated the assets and captured synergies to date. The Company targets go forward operating costs based on current strip estimates, including energy costs, to be approximately $8.00 - $9.00/bbl**.** This represents a $3.50/bbl reduction at the midpoint or approximately 30% lower than operating cost indications for the asset at the time of acquisition.
    ◦ At Jackfish, the Company successfully completed tie in activities in Q4/19 on the previously drilled pad additions that have production capability of 21,000 bbl/d for minimal capital of approximately $8 million. Production from these pads is targeted to reach overall peak production in early 2022 and is targeted to offset conventional production declines with long life low decline thermal in situ production as the Company manages within its curtailment optimization strategy.
    ◦ The Company is targeting planned turnaround activity in late Q1/20 at Jackfish. Production impacts are reflected in annual guidance and will be managed as part of the Company's curtailment optimization strategy.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Natural gas production (MMcf/d)	**1,411**	1,425	1,441	**1,443**	1,490
Net wells targeting natural gas	**4**	5	3	**20**	18
Net successful wells drilled	**4**	5	3	**19**	18
Success rate	**100%**	100%	100%	**95%**	100%

▪ North America natural gas production was 1,443 MMcf/d in 2019, a decrease of 3% from 2018 levels, reflecting natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

▪ Natural gas operating costs were strong in 2019, a decrease of 7% from 2018 levels to $1.16/Mcf, given the Company's strategic decision to allocate capital to other areas and let production decline. These results demonstrate the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control and achieving efficiencies across the entire asset base.
    - At the Company's high value Septimus Montney liquids rich area, operating costs were strong in 2019, a 6% decrease from 2018 levels, averaging $0.30/Mcfe in 2019.

▪ The Company's Liquids Enhancement and Gas Storage ("LEGS") pilot at Septimus began in Q2/19 and has the potential to materially increase liquids recovery while storing natural gas in the reservoir, preserving the value of the natural gas for periods with higher market prices.
    - The Company completed two injection and production cycles at Septimus in 2019 and initial results are positive, indicating incremental liquids recovery within the expected range of 1.3x to 1.7x primary recovery. A third production cycle commenced in February 2020 and is proceeding as expected. Given the opportunities for this process across Canadian Natural's vast liquids rich Montney land base, the Company is executing on a second pilot site within the Company's Greater Wembley area and is targeting first injection in late Q2/20.

▪ Following the acquisition of the Pine River plant in Q2/19, the Company successfully completed a planned plant turnaround in Q4/19 designed to improve plant efficiency, run time, lower operating costs, and improve plant capability. Following the turnaround, plant capability has improved to 120 MMcf/d from previous levels of 95 MMcf/d.

- In 2019, Canadian Natural used the equivalent of approximately 44% of corporate annual natural gas production within its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 34% of the Company's 2019 natural gas production was exported to other North American markets and sold internationally, while the remaining 22% of the Company's 2019 natural gas production was exposed to AECO/Station 2 pricing.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil production (bbl/d)					
North Sea	**30,860**	27,454	21,071	**27,919**	23,965
Offshore Africa	**18,495**	21,227	22,185	**21,371**	19,662
Natural gas production (MMcf/d)					
North Sea	**25**	20	22	**24**	32
Offshore Africa	**19**	24	25	**24**	26
Net wells targeting crude oil	**—**	3.0	1.1	**5.5**	5.6
Net successful wells drilled	**—**	3.0	1.1	**5.5**	5.6
Success rate	**—**	100%	100%	**100%**	100%

- International E&P crude oil production volumes were strong in 2019, averaging 49,290 bbl/d, an increase of 13% over 2018 levels. The increase over 2018 was primarily due to strong performance from wells drilled in the North Sea and at Baobab, partially offset by natural field declines.
- International production volumes benefit from premium Brent pricing, generating significant free cash flow for the Company.
  - In the North Sea, crude oil production volumes of 27,919 bbl/d were achieved in 2019, a 16% increase over 2018 levels, reflecting volumes from new wells after a successful 2019 drilling program of 5 gross (4.9 net) wells.
    - 2019 operating costs in the North Sea decreased by 9% from 2018 levels, averaging $36.39/bbl (£21.27/bbl), reflecting increased production volumes, together with fluctuations in the Canadian dollar.
    - The North Sea 2020 drilling program, targeting 6 gross (5.9 net) producer and 2 gross (1.9 net) injector wells, commenced in Q1/20 at Ninian.
  - Offshore Africa crude oil production volumes in 2019 averaged 21,371 bbl/d, a 9% increase over 2018 levels, primarily as a result of production from wells drilled in late 2018 and early 2019 at Baobab, partially offset by natural field declines.
    - Côte d'Ivoire crude oil operating costs decreased 16% from 2018 levels, averaging $11.21/bbl (US$8.45/bbl) in 2019, primarily due to timing of liftings from various fields that have different cost structures.
    - The Company is targeting planned turnaround activities at Espoir in Q1/20 and at Baobab in Q2/20.
    - Following the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural has a 20% working interest, the operator commenced a comprehensive 3D and 2D seismic acquisition program in Q4/19, with targeted completion in Q2/20.
      - The operator has contracted a rig with targeted spud of an exploration well in Q2/20. Depending on the results of this well, the operator may drill an additional well in 2020 to further define volumes and deliverability.
      - Canadian Natural is carried to a maximum gross cost of approximately US$300 million.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Synthetic crude oil production (bbl/d) (1) (2)	**357,856**	432,203	447,048	**395,133**	426,190

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

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

- At the Company's world class Oil Sands Mining and Upgrading assets, annual production volumes averaged 395,133 bbl/d of SCO in 2019, a decrease of 7% from 2018 levels, reflecting the proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year.
  - Effective and efficient operations resulted in annual operating costs, excluding energy costs, of $3,276 million, a $91 million or 3% decrease from 2018 levels.
  - Industry leading annual operating costs averaged $22.56/bbl of SCO, a 4% increase from 2018 levels primarily reflecting reduced production volumes together with increased natural gas costs.
  - At AOSP, through increased reliability, process improvements and optimization projects, Canadian Natural increased gross production capacity at the Albian mines by approximately 40,000 bbl/d to approximately 320,000 bbl/d, representing a 14% increase in capacity while reducing AOSP operating costs by approximately 34% or $10.00/bbl since the announcement of the acquisition in 2017.
  - As part of the Company's overall strategy to maximize value and enhance margins, the Scotford Upgrader is targeting to increase capacity to approximately 320,000 bbl/d in Q3/20. This additional capacity at AOSP will allow for increased flexibility, margin improvements and can be managed through the Company's curtailment optimization strategy.
  - At the Albian mines, top tier operations combined with optimization of facilities resulted in record gross bitumen production averaging approximately 306,000 bbl/d in Q4/19, forming a part of the Company’s curtailment optimization strategy during the turnaround and the proactive piping replacement at Horizon.
  - In Q4/19 at Horizon, as a result of Canadian Natural's industry leading integrity program, the Company identified the need to replace piping on one of the hydrogen manufacturing units during post turnaround start-up. To ensure increased reliability of operations and as part of the Company's curtailment optimization strategy, the Company made the proactive decision to replace the piping, at which time Horizon ran at restricted rates of approximately 170,500 bbl/d, and production impacts were managed as part of the Company's curtailment optimization strategy. The proactive piping replacement was completed for approximately $65 million and production resumed to full rates on January 19, 2020.
    - Record monthly production of approximately 262,600 bbl/d of SCO was achieved at Horizon in February 2020 as a result of continued high utilization, safe, steady and reliable operations.
  - At the non-operated Scotford Upgrader, a planned 55 day turnaround is targeted to start in April 2020, at which time the Upgrader will run at gross restricted rates of approximately 160,000 bbl/d of SCO. Timing of planned pit stop activities at the AOSP mines is aligned with the planned turnaround at the Scotford Upgrader. Production impacts are reflected in the Company's annual 2020 guidance and will be managed as part of the Company's curtailment optimization strategy.
  - The Company continues to progress engineering work on a prudent basis for potential expansion opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The final investment decision on these opportunities will not be made until there is greater clarity on market access.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 56.96**	$ 56.45	$ 58.83	**$ 57.04**	$ 64.78
WCS heavy differential as a percentage of WTI (%) [2]	**28%**	22%	67%	**22%**	41%
SCO price (US$/bbl)	**$ 56.32**	$ 56.87	$ 37.48	**$ 56.35**	$ 58.62
Condensate benchmark pricing (US$/bbl)	**$ 52.99**	$ 52.00	$ 45.27	**$ 52.84**	$ 60.98
Average realized pricing before risk management (C$/bbl) [3]	**$ 49.60**	$ 55.19	$ 25.95	**$ 55.08**	$ 46.92
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.21**	$ 0.99	$ 1.80	**$ 1.54**	$ 1.45
Average realized pricing before risk management (C$/Mcf)	**$ 2.64**	$ 1.64	$ 3.46	**$ 2.34**	$ 2.61

(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.

- Mainline enhancements of approximately 100,000 bbl/d of capacity were completed in December 2019, increasing pipeline capacity out of the WCSB.
- Additional pipeline egress of approximately 190,000 bbl/d to move incremental crude oil production out of the WCSB is targeted to be added by industry over the near term, providing opportunities for the Company before new export pipelines are constructed:
  - Additional Mainline enhancements of 50,000 bbl/d of capacity is targeted in 2020.
  - Express pipeline optimization expansion is targeted to add approximately 50,000 bbl/d of capacity in 2020.
  - The NWR Refinery is targeted to add approximately 40,000 bbl/d of incremental crude oil conversion capacity. Upon start-up of the Gasifier and LC Finer units, the refinery will process a total of approximately 80,000 bbl/d of diluted bitumen, increasing effective takeaway capacity out of the WCSB.
    - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.
  - Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available in 2020.
- Crude by rail volumes continue to be strong at approximately 350,000 bbl/d for the month of December 2019.
- 2019 differentials between WCS and WTI benchmark pricing narrowed from 2018 levels following the Government of Alberta's announcement of mandatory curtailments of crude oil production that came into effect January 1, 2019.
- AECO natural gas prices increased in Q4/19 from Q3/19 and Q4/18 levels, reflecting additional egress capability, seasonal demand factors and the impact of the TC Energy Temporary Service Protocol in Q4/19.

GOVERNANCE

- As part of the Company's ongoing Governance process, Steve W. Laut, who was appointed Executive Vice-Chairman in March 2018 after serving as President for the previous 13 years, has decided to step back from the day to day operations of the Company at or before the Company's Annual General Meeting ("AGM") in May 2020. Mr. Laut will remain on the Board of Directors (the "Board") and stand for re-election at the 2020 AGM.
- As previously announced Dr. M. Elizabeth Cannon was appointed to the Board effective November 5, 2019 and will stand for election at the 2020 AGM. Dr. Cannon has many significant accomplishments with the most recent being President Emerita and Professor of Engineering at the University of Calgary having previously served at the University

of Calgary as Dean of the Schulich School of Engineering from 2006-2010, President and Vice Chancellor from 2010 to 2018.

- Timothy W. Faithfull will be stepping down from the Board in accordance with the Company's mandatory retirement policy. Mr. Faithfull has been a valued member of the Board of Directors, serving as a member since November 2010.

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 1,098,957 BOE/d in 2019, with approximately 98% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with 2019 production mix on a BOE/d basis of 49% light crude oil and SCO blends, 28% heavy crude oil blends and 23% natural gas.
- Canadian Natural delivered record annual free cash flow of $4,620 million after net capital expenditures of $3,904 million and dividend requirements of $1,743 million, and excluding Devon Canada asset acquisition costs, reflecting the strength of the Company's long life low decline asset base and effective and efficient operations.
  - Balance sheet strength remains a focus as year end 2019 long-term debt totaled $20,982 million, comparable to Q1/19 levels prior to the Devon Canada asset acquisition, and debt to book capitalization strengthened to 37.3% from 39.1% at year end 2018 while debt to adjusted EBITDA improved to 1.9x from 2.0x at year end 2018. During 2019, the Company executed on the following:
    - The Company repaid $500 million of 3.05% notes and $500 million of 2.60% notes in Q2/19 and Q4/19, respectively.
    - The Company fully repaid and cancelled the remaining balance of the $1,800 million non-revolving term loan credit facility that was used to finance the AOSP acquisition, ahead of its maturity in May 2020.
    - In Q4/19, the Company extended the $2,425 million revolving syndicated credit facility scheduled to mature in June 2021 to June 2023. Additionally, the $2,200 million non-revolving term credit facility, originally due in October 2020, was extended to February 2023 and increased by $450 million to $2,650 million.
    - Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At December 31, 2019, the Company had approximately $4,876 million of available liquidity, including cash and cash equivalents, an increase of approximately $52 million and $196 million over 2018 and Q3/19 levels respectively.
  - Canadian Natural is committed to returns to shareholders, returning a total of $2,684 million to shareholders in 2019, $1,743 million by way of dividends and $941 million by way of share repurchases.
    - Share repurchases for cancellation totaled 25,900,000 common shares at a weighted average share price of $36.32.
    - Subsequent to year end, up to and including March 4, 2020, the Company executed on additional share repurchases for cancellation of 6,600,000 common shares at a weighted average share price of $39.41.
    - Returns to shareholders have been significant as Canadian Natural returned approximately $6.2 billion by way of dividends and share repurchases between January 1, 2018 and March 4, 2020.
    - 2019 dividends increased 12% from 2018 levels to $1.50 per share. Subsequent to year end, the Company declared a quarterly dividend increase of 13% to $0.425 per share, payable on April 1, 2020. The increase marks the 20th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's strength and robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
- In addition to the Company's strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at December 31, 2019, these financial levers include the Company's third party equity investments of $490 million, and cross currency swaps with a total value of $290 million.

OUTLOOK

The Company targets annual 2020 production levels to average between 910,000 bbl/d and 970,000 bbl/d of crude oil and NGLs and between 1,360 MMcf/d and 1,420 MMcf/d of natural gas, before royalties. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

Canadian Natural's annual 2020 capital expenditures are targeted to be approximately $3.95 billion.

2019 YEAR-END RESERVES

Determination of Reserves

For the year ended December 31, 2019, 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 evaluation and review was conducted and prepared 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.

Summary of Company Gross Reserves

As of December 31, 2019
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	97	103	235	653	6,219	3,150	92	7,925
Developed Non-Producing	12	14	—	14	—	162	6	72
Undeveloped	56	85	58	1,771	133	3,083	177	2,794
Total Proved	165	202	293	2,438	6,352	6,395	275	10,791
Probable	64	91	132	1,670	545	3,118	133	3,156
Total Proved plus Probable	229	293	425	4,108	6,897	9,513	408	13,947
North Sea								
Proved								
Developed Producing	37					10		39
Developed Non-Producing	4					1		4
Undeveloped	68					5		69
Total Proved	109					16		112
Probable	67					5		68
Total Proved plus Probable	176					21		179
Offshore Africa								
Proved								
Developed Producing	32					29		37
Developed Non-Producing	12					6		13
Undeveloped	39					13		41
Total Proved	83					48		91
Probable	31					24		35
Total Proved plus Probable	114					72		126
Total Company								
Proved								
Developed Producing	166	103	235	653	6,219	3,189	92	8,001
Developed Non-Producing	28	14	—	14	—	169	6	90
Undeveloped	163	85	58	1,771	133	3,101	177	2,903
Total Proved	357	202	293	2,438	6,352	6,460	275	10,993
Probable	162	91	132	1,670	545	3,147	133	3,258
Total Proved plus Probable	519	293	425	4,108	6,897	9,607	408	14,252

Reconciliation of Company Gross Reserves

As of December 31, 2019
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, 2018	194	182	305	1,540	6,091	6,597	267	9,679
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(3)	(3)	(3)	—	—	(228)	(5)	(53)
Technical Revisions	(16)	(3)	12	(64)	20	198	11	(8)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**165**	**202**	**293**	**2,438**	**6,352**	**6,395**	**275**	**10,791**
North Sea								
December 31, 2018	119					27		124
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	(2)					—		(2)
Technical Revisions	2					(2)		2
Production	(10)					(9)		(12)
December 31, 2019	**109**					**16**		**112**
Offshore Africa								
December 31, 2018	86					28		90
Discoveries	—					—		—
Extensions	—					—		—
Infill Drilling	—					—		—
Improved Recovery	—					—		—
Acquisitions	—					—		—
Dispositions	—					—		—
Economic Factors	—					—		—
Technical Revisions	5					29		10
Production	(8)					(9)		(9)
December 31, 2019	**83**					**48**		**91**
Total Company								
December 31, 2018	399	182	305	1,540	6,091	6,652	267	9,893
Discoveries	—	—	—	—	—	—	—	—
Extensions	3	6	—	17	385	112	11	440
Infill Drilling	5	5	—	—	—	206	8	52
Improved Recovery	—	—	—	237	—	2	—	238
Acquisitions	2	46	—	769	—	35	1	823
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(5)	(3)	(3)	—	—	(228)	(5)	(54)
Technical Revisions	(9)	(3)	12	(64)	20	225	11	3
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**357**	**202**	**293**	**2,438**	**6,352**	**6,460**	**275**	**10,993**

Reconciliation of Company Gross Reserves

As of December 31, 2019
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, 2018	268	252	445	3,059	7,032	9,633	397	13,058
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(29)	(12)	4	(198)	9	(26)	(1)	(230)
Production	(19)	(30)	(21)	(61)	(144)	(527)	(16)	(380)
December 31, 2019	**229**	**293**	**425**	**4,108**	**6,897**	**9,513**	**408**	**13,947**

North Sea	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2018	186	38	193
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	—	(9)	(2)
Production	(10)	(9)	(12)
December 31, 2019	**176**	**21**	**179**

Offshore Africa	Light and Medium Crude Oil (MMbbl)	Natural Gas (Bcf)	Barrels of Oil Equivalent (MMBOE)
December 31, 2018	121	63	131
Discoveries	—	—	—
Extensions	—	—	—
Infill Drilling	—	—	—
Improved Recovery	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	—	—	—
Technical Revisions	—	18	3
Production	(8)	(9)	(9)
December 31, 2019	**114**	**72**	**126**

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, 2018	575	252	445	3,059	7,032	9,734	397	13,382
Discoveries	—	—	—	—	—	—	—	—
Extensions	4	12	—	26	—	177	17	89
Infill Drilling	6	7	—	—	—	476	15	108
Improved Recovery	—	—	—	329	—	3	—	329
Acquisitions	2	68	—	955	—	42	1	1,033
Dispositions	—	—	—	—	—	—	—	—
Economic Factors	(4)	(3)	(3)	—	—	(266)	(6)	(60)
Technical Revisions	(28)	(12)	4	(198)	9	(16)	(1)	(228)
Production	(37)	(30)	(21)	(61)	(144)	(544)	(16)	(401)
December 31, 2019	**519**	**293**	**425**	**4,108**	**6,897**	**9,607**	**408**	**14,252**

NOTES TO RESERVES:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates were provided by Sproule Associates Limited:

	2020	*2021*	*2022*	*2023*	*2024*
Crude oil and NGL					
WTI at Cushing (US$/bbl)	61.00	65.00	67.00	68.34	69.71
Western Canada Select (C$/bbl)	59.81	63.98	63.77	65.04	66.34
Canadian Light Sweet (C$/bbl)	73.84	78.51	78.73	80.30	81.91
Cromer LSB (C$/bbl)	73.84	77.51	77.73	79.30	80.91
Edmonton Pentanes+ (C$/bbl)	76.32	80.52	80.00	81.68	83.38
North Sea Brent (US$/bbl)	65.00	68.00	70.00	71.40	72.83
Natural gas					
AECO (C$/MMBtu)	2.04	2.27	2.81	2.89	2.98
BC Westcoast Station 2 (C$/MMBtu)	1.54	1.87	2.41	2.49	2.58
Henry Hub (US$/MMBtu)	2.80	3.00	3.25	3.32	3.38

   All prices increase at a rate of 2%/year after 2024.

   A foreign exchange rate of 0.7600 US$/C$ for 2020, 0.7700 US$/C$ for 2021 and 0.8000 US$/C$ after 2021 was used in the 2019 evaluation.

4. 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.
5. Oil and gas metrics included herein are commonly used in the crude 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.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. 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.
8. Reserves Life Index is based on the amount for the relevant reserves category divided by the 2020 proved developed producing production forecast prepared by the Independent Qualified Reserves Evaluators.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2019 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2019 and net changes in FDC from December 31, 2018 to December 31, 2019 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue (FNR) for 2019 consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2019 and forecast estimates of ADR costs attributable to future development activity.

ADVISORY

Special Note Regarding non-GAAP Financial Measures

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

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

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

Net capital expenditures is a non-GAAP measure that represents cash flows used in investing activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, investment in other long-term assets, share consideration in business acquisitions and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the Net Capital Expenditures section of the Company's MD&A.

Free cash flow is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital from operating activities, abandonment, certain movements in other long-term assets, less net capital expenditures and dividends on common shares. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders, and to repay debt.

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

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

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

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

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ADVISORY

Special Note Regarding Forward-Looking Statements

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

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

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

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

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

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations) and net capital expenditures. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (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 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, 2019 and the MD&A and the audited consolidated financial statements of the Company for the year ended December 31, 2018. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's unaudited interim consolidated financial statements for the three months and year ended December 31, 2019 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB"). Changes in the Company's accounting policies in accordance with IFRS, including the adoption of IFRS 16 "Leases" on January 1, 2019, are discussed in the "Changes in Accounting Policies" section of this MD&A. In accordance with the new IFRS 16 "Leases" standard, comparative period balances in 2018 reported in this MD&A have not been restated.

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

The following discussion and analysis refers primarily to the Company's financial results for the three months and year ended December 31, 2019 in relation to the comparable periods in 2018 and the third quarter of 2019. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. Information on the Company's website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 4, 2020.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Dec 31 2019**	Sep 30 2019	Dec 31 2018	Year Ended **Dec 31 2019**	Dec 31 2018
Product sales [1]	**$ 6,335**	$ 6,587	$ 3,831	**$ 24,394**	$ 22,282
Crude oil and NGLs	**$ 5,947**	$ 6,324	$ 3,327	**$ 22,950**	$ 20,668
Natural gas	**$ 382**	$ 257	$ 504	**$ 1,419**	$ 1,614
Net earnings (loss)	**$ 597**	$ 1,027	$ (776)	**$ 5,416**	$ 2,591
Per common share – basic	**$ 0.50**	$ 0.87	$ (0.64)	**$ 4.55**	$ 2.13
– diluted	**$ 0.50**	$ 0.87	$ (0.64)	**$ 4.54**	$ 2.12
Adjusted net earnings (loss) from operations [2]	**$ 686**	$ 1,229	$ (255)	**$ 3,795**	$ 3,263
Per common share – basic	**$ 0.58**	$ 1.04	$ (0.21)	**$ 3.19**	$ 2.68
– diluted	**$ 0.58**	$ 1.04	$ (0.21)	**$ 3.18**	$ 2.67
Cash flows from operating activities	**$ 2,454**	$ 2,518	$ 1,397	**$ 8,829**	$ 10,121
Adjusted funds flow [3]	**$ 2,494**	$ 2,881	$ 1,229	**$ 10,267**	$ 9,088
Per common share – basic	**$ 2.11**	$ 2.43	$ 1.02	**$ 8.62**	$ 7.46
– diluted	**$ 2.10**	$ 2.43	$ 1.02	**$ 8.61**	$ 7.43
Cash flows used in investing activities	**$ 854**	$ 908	$ 1,042	**$ 7,255**	$ 4,814
Net capital expenditures [4]	**$ 1,056**	$ 963	$ 1,181	**$ 7,121**	$ 4,731

(1) Further details related to product sales, including 'Other' income, for the three months and year ended December 31, 2019 are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

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

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

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

($ millions)	Three Months Ended Dec 31 2019	Three Months Ended Sep 30 2019	Three Months Ended Dec 31 2018	Year Ended Dec 31 2019	Year Ended Dec 31 2018
Net earnings (loss)	**$ 597**	$ 1,027	$ (776)	**$ 5,416**	$ 2,591
Share-based compensation, net of tax (1)	**148**	7	(148)	**210**	(146)
Unrealized risk management loss (gain), net of tax (2)	**16**	(2)	17	**14**	(36)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(225)**	129	548	**(548)**	706
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax (4)	**—**	—	—	**—**	146
Loss from investments, net of tax (5) (6)	**150**	68	134	**321**	374
Gain on acquisition, disposition and revaluation of properties, net of tax (7)	**—**	—	(30)	**—**	(372)
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (8)	**—**	—	—	**(1,618)**	—
Adjusted net earnings (loss) from operations	**$ 686**	$ 1,229	$ (255)	**$ 3,795**	$ 3,263

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. 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 from investments is the Company's pro rata share of the Redwater Partnership's equity loss recognized 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.

(8) All substantively enacted adjustments in applicable income tax rates and other legislative changes are applied to the underlying assets and liabilities on the Company's balance sheets in determining deferred income tax assets and liabilities. The impact of these tax rate and other legislative changes is recorded in net earnings during the period the legislation is substantively enacted. In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. As a result of these corporate income tax rate reductions, the Company's deferred corporate income tax liability decreased by $1,618 million.

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

($ millions)	Three Months Ended Dec 31 2019	Three Months Ended Sep 30 2019	Three Months Ended Dec 31 2018	Year Ended Dec 31 2019	Year Ended Dec 31 2018
Cash flows from operating activities	**$ 2,454**	$ 2,518	$ 1,397	**$ 8,829**	$ 10,121
Net change in non-cash working capital	**(52)**	299	(279)	**1,033**	(1,346)
Abandonment expenditures (2)	**84**	63	93	**296**	290
Other (3)	**8**	1	18	**109**	23
Adjusted funds flow	**$ 2,494**	$ 2,881	$ 1,229	**$ 10,267**	$ 9,088

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

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

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

Net earnings for the year ended December 31, 2019 were $5,416 million compared with $2,591 million for the year ended December 31, 2018. Net earnings for the year ended December 31, 2019 included net after-tax income of $1,621 million compared with net after-tax expenses of $672 million for the year ended December 31, 2018 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates including the impact of realized foreign exchange losses on repayments of long-term debt, the loss from investments, the gain on acquisition, 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, 2019 were $3,795 million compared with $3,263 million for the year ended December 31, 2018.

Net earnings for the fourth quarter of 2019 were $597 million compared with a net loss of $776 million for the fourth quarter of 2018 and net earnings of $1,027 million for the third quarter of 2019. Net earnings for the fourth quarter of 2019 included net after-tax expenses of $89 million compared with net after-tax expenses of $521 million for the fourth quarter of 2018 and net after-tax expenses of $202 million for the third quarter of 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss from investments and the gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2019 were $686 million compared with adjusted net loss from operations of $255 million for the fourth quarter of 2018 and adjusted net earnings from operations of $1,229 million for the third quarter of 2019.

The increase in net earnings and adjusted net earnings from operations for the year ended December 31, 2019 compared with the year ended December 31, 2018 primarily reflected:

- higher crude oil and NGLs sales volumes and netbacks in the Exploration and Production segments; and
- higher realized foreign exchange gains;

partially offset by:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower natural gas netbacks in the Exploration and Production segments; and
- higher realized risk management losses.

The increase in net earnings and adjusted net earnings from operations for the fourth quarter of 2019 compared with the fourth quarter of 2018 primarily reflected:

- higher crude oil and NGLs netbacks in the Exploration and Production segments;
- higher realized SCO prices in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs sales volumes in the North America and North Sea segments;

partially offset by:

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

The decrease in net earnings and adjusted net earnings from operations for the fourth quarter of 2019 compared with the third quarter of 2019 primarily reflected:

- lower SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower crude oil and NGLs netbacks in the North America and North Sea segments; and
- lower crude oil and NGLs sales volumes in the Offshore Africa segment;

partially offset by:

- higher natural gas netbacks in the Exploration and Production segments; and
- higher crude oil and NGLs sales volumes in the North America and North Sea segments.

Net earnings for the year ended December 31, 2019 also reflected the Government of Alberta enacted decrease in the provincial corporate income tax rate from 12% to 11% effective July 1, 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022. This resulted in a decrease in the Company's deferred corporate income tax liability of $1,618 million. See the "Income Taxes" section of this MD&A.

For the three months and year ended December 31, 2019, the impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings from the comparable periods. The adoption of IFRS 16 did not have a significant overall impact on net earnings or adjusted net earnings from operations. 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, 2019 were $8,829 million compared with $10,121 million for the year ended December 31, 2018. Cash flows from operating activities for the fourth quarter of 2019 were $2,454 million compared with $1,397 million for the fourth quarter of 2018 and $2,518 million for the third quarter of 2019. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effects of depletion, depreciation and amortization and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2019 was $10,267 million compared with $9,088 million for the year ended December 31, 2018. Adjusted funds flow for the fourth quarter of 2019 was $2,494 million compared with $1,229 million for the fourth quarter of 2018 and $2,881 million for the third quarter of 2019. 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 expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Cash flows from operating activities and adjusted funds flow for the year ended December 31, 2019 reflected an increase of $237 million related to the adoption of IFRS 16 on January 1, 2019 as the principal portions of lease payments previously classified as cash flows from operating activities are now reported as cash flows used in financing activities. The adoption of IFRS 16 is discussed in the "Changes in Accounting Policies" section of this MD&A.

Production Volumes

Total production before royalties for the fourth quarter of 2019 increased 7% to 1,156,276 BOE/d from 1,081,368 BOE/d for the fourth quarter of 2018 and was comparable with 1,176,361 BOE/d for the third quarter of 2019. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)		**Dec 31 2019**		Sep 30 2019		Jun 30 2019		Mar 31 2019
Product sales [1]	**$**	**6,335**	$	6,587	$	5,931	$	5,541
Crude oil and NGLs	**$**	**5,947**	$	6,324	$	5,597	$	5,082
Natural gas	**$**	**382**	$	257	$	324	$	456
Net earnings (loss)	**$**	**597**	$	1,027	$	2,831	$	961
Net earnings (loss) per common share								
– basic	**$**	**0.50**	$	0.87	$	2.37	$	0.80
– diluted	**$**	**0.50**	$	0.87	$	2.36	$	0.80
($ 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

(1) Further details related to product sales, including 'Other' income, for the three months ended December 31, 2019 are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

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

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
(Average for the period)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
WTI benchmark price (US$/bbl)	**$ 56.96**	$ 56.45	$ 58.83	**$ 57.04**	$ 64.78
Dated Brent benchmark price (US$/bbl)	**$ 62.64**	$ 61.85	$ 67.45	**$ 64.04**	$ 71.12
WCS Heavy Differential from WTI (US$/bbl)	**$ 15.84**	$ 12.24	$ 39.36	**$ 12.79**	$ 26.29
SCO price (US$/bbl)	**$ 56.32**	$ 56.87	$ 37.48	**$ 56.35**	$ 58.62
Condensate benchmark price (US$/bbl)	**$ 52.99**	$ 52.00	$ 45.27	**$ 52.84**	$ 60.98
Condensate Differential from WTI (US$/bbl)	**$ 3.97**	$ 4.45	$ 13.56	**$ 4.20**	$ 3.80
NYMEX benchmark price (US$/MMBtu)	**$ 2.50**	$ 2.23	$ 3.65	**$ 2.63**	$ 3.08
AECO benchmark price (C$/GJ)	**$ 2.21**	$ 0.99	$ 1.80	**$ 1.54**	$ 1.45
US/Canadian dollar average exchange rate (US$)	**$ 0.7576**	$ 0.7573	$ 0.7573	**$ 0.7536**	$ 0.7717

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

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$57.04 per bbl for the year ended December 31, 2019, a decrease of 12% from US$64.78 per bbl for the year ended December 31, 2018. WTI averaged US$56.96 per bbl for the fourth quarter of 2019, a decrease of 3% from US$58.83 per bbl for the fourth quarter of 2018, and comparable with US$56.45 per bbl for the third quarter of 2019.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$64.04 per bbl for the year ended December 31, 2019, a decrease of 10% from US$71.12 per bbl for the year ended December 31, 2018. Brent averaged US$62.64 per bbl for the fourth quarter of 2019, a decrease of 7% from US$67.45 per bbl for the fourth quarter of 2018, and comparable with US$61.85 per bbl for the third quarter of 2019.

WTI and Brent pricing for the three months and year ended December 31, 2019 has decreased from the comparable periods in 2018 primarily due to increases in non-OPEC crude oil supply. In addition, global crude oil pricing has been impacted by ongoing trade disputes between the US and China.

The WCS Heavy Differential averaged US$12.79 per bbl for the year ended December 31, 2019, a decrease of 51% from US$26.29 per bbl for the year ended December 31, 2018. The WCS Heavy Differential averaged US$15.84 per bbl for the fourth quarter of 2019, a decrease of 60% from US$39.36 per bbl for the fourth quarter of 2018, and an increase of 29% from US$12.24 per bbl for the third quarter of 2019. The narrowing of the WCS Heavy Differential for the three months and year ended December 31, 2019 from the comparable periods in 2018 primarily reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The widening of the differential for the fourth quarter of 2019 as compared with the third quarter of 2019 primarily reflected seasonality.

The SCO price averaged US$56.35 per bbl for the year ended December 31, 2019, a decrease of 4% from US$58.62 per bbl for the year ended December 31, 2018. The SCO price averaged US$56.32 per bbl for the fourth quarter of 2019, an increase of 50% from US$37.48 per bbl for the fourth quarter of 2018, and comparable with US$56.87 per bbl for the third quarter of 2019. The increase in the SCO price for the fourth quarter of 2019 as compared with the fourth quarter of 2018 primarily reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

NYMEX natural gas prices averaged US$2.63 per MMBtu for the year ended December 31, 2019, a decrease of 15% from US$3.08 per MMBtu for the year ended December 31, 2018. NYMEX natural gas prices averaged US$2.50 per MMBtu for the fourth quarter of 2019, a decrease of 32% from US$3.65 per MMBtu for the fourth quarter of 2018, and an increase of 12% from US$2.23 per MMBtu for the third quarter of 2019. The decrease in NYMEX natural gas prices for the three months and year ended December 31, 2019 from the comparable periods in 2018 primarily reflected increased production levels in North America and the impact of seasonal weather conditions. The increase in NYMEX natural gas prices for the fourth quarter of 2019 as compared with the third quarter of 2019 primarily reflected increased Liquefied Natural Gas ("LNG") exports out of the US Gulf Coast and seasonal demand factors.

AECO natural gas prices averaged $1.54 per GJ for the year ended December 31, 2019, an increase of 6% from $1.45 per GJ for the year ended December 31, 2018. AECO natural gas prices averaged $2.21 per GJ for the fourth quarter of 2019, an increase of 23% from $1.80 per GJ for the fourth quarter of 2018, and an increase of 123% from $0.99 per GJ for the third quarter of 2019. The increase in AECO natural gas prices for the three months and year ended December 31, 2019 from the comparable periods primarily reflected additional egress capability, seasonal demand factors, and the impact of the TC Energy Temporary Service Protocol in the fourth quarter of 2019.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**506,571**	450,662	343,054	**405,970**	350,961
North America – Oil Sands Mining and Upgrading [1]	**357,856**	432,203	447,048	**395,133**	426,190
North Sea	**30,860**	27,454	21,071	**27,919**	23,965
Offshore Africa	**18,495**	21,227	22,185	**21,371**	19,662
	913,782	931,546	833,358	**850,393**	820,778
Natural gas (MMcf/d)					
North America	**1,411**	1,425	1,441	**1,443**	1,490
North Sea	**25**	20	22	**24**	32
Offshore Africa	**19**	24	25	**24**	26
	1,455	1,469	1,488	**1,491**	1,548
Total barrels of oil equivalent (BOE/d)	**1,156,276**	1,176,361	1,081,368	**1,098,957**	1,078,813
Product mix					
Light and medium crude oil and NGLs	**12%**	12%	13%	**13%**	13%
Pelican Lake heavy crude oil	**5%**	5%	6%	**5%**	6%
Primary heavy crude oil	**8%**	8%	7%	**8%**	8%
Bitumen (thermal oil)	**23%**	18%	10%	**15%**	10%
Synthetic crude oil	**31%**	36%	41%	**36%**	39%
Natural gas	**21%**	21%	23%	**23%**	24%
Percentage of gross revenue [1] [2] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**94%**	97%	85%	**94%**	93%
Natural gas	**6%**	3%	15%	**6%**	7%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**438,894**	397,456	304,324	**356,794**	303,956
North America – Oil Sands Mining and Upgrading	**340,262**	407,592	421,421	**375,048**	405,731
North Sea	**30,815**	27,399	21,021	**27,866**	23,902
Offshore Africa	**17,294**	20,095	21,366	**20,078**	18,450
	827,265	852,542	768,132	**779,786**	752,039
Natural gas (MMcf/d)					
North America	**1,351**	1,421	1,396	**1,400**	1,432
North Sea	**25**	20	22	**24**	32
Offshore Africa	**18**	22	22	**22**	23
	1,394	1,463	1,440	**1,446**	1,487
Total barrels of oil equivalent (BOE/d)	**1,059,562**	1,096,329	1,008,210	**1,020,749**	999,857

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

Crude oil and NGLs production before royalties for the year ended December 31, 2019 averaged 850,393 bbl/d, an increase of 4% from 820,778 bbl/d for the year ended December 31, 2018. Crude oil and NGLs production for the fourth quarter of 2019 of 913,782 bbl/d increased 10% from 833,358 bbl/d for the fourth quarter of 2018, and was comparable with 931,546 bbl/d for the third quarter of 2019. The increase in crude oil and NGLs production for the year ended December 31, 2019 from the year ended December 31, 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The increase in crude oil and NGLs production for the fourth quarter of 2019 from the fourth quarter of 2018 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon, offsetting the impact of the completion of the planned turnaround and a proactive piping replacement at Horizon in the fourth quarter of 2019. The Company continues to optimize its production volumes across the asset base during curtailment.

Annual 2019 crude oil and NGLs production before royalties was within the Company's previously issued guidance of 839,000 to 888,000 bbl/d. Annual crude oil and NGLs production guidance for 2020 is targeted to average between 910,000 and 970,000 bbl/d.

Natural gas production before royalties for the year ended December 31, 2019 decreased 4% to 1,491 MMcf/d from 1,548 MMcf/d for the year ended December 31, 2018. Natural gas production for the fourth quarter of 2019 of 1,455 MMcf/d was comparable with 1,488 MMcf/d for the fourth quarter of 2018, and with 1,469 MMcf/d for the third quarter of 2019. The decrease in natural gas production for the year ended December 31, 2019 from the year ended December 31, 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

Annual 2019 natural gas production before royalties was within the Company's previously issued guidance of 1,485 to 1,545 MMcf/d. Annual natural gas production guidance for 2020 is targeted to average between 1,360 and 1,420 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the year ended December 31, 2019 averaged 405,970 bbl/d, an increase of 16% from 350,961 bbl/d for the year ended December 31, 2018. North America crude oil and NGLs production for the fourth quarter of 2019 of 506,571 bbl/d increased 48% from 343,054 bbl/d for the fourth quarter of 2018, and increased 12% from 450,662 bbl/d for the third quarter of 2019. The increase in production for the three months and year ended December 31, 2019 from the comparable periods primarily reflected the acquisition of thermal and heavy oil assets from Devon that closed on June 27, 2019, and increased production of thermal oil due to additional production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base. The Company achieved record production levels in the North America Exploration and Production segment in the fourth quarter of 2019.

Thermal oil production before royalties for the fourth quarter of 2019 averaged 259,387 bbl/d compared with 102,112 bbl/d for the fourth quarter of 2018 and 206,395 bbl/d for the third quarter of 2019. Thermal oil production in the fourth quarter of 2019 reflected volumes from the acquisition of assets from Devon, together with new production from Kirby North and pad additions at Primrose, reflecting optimization of curtailment volumes across the Company's asset base. Annual 2019 thermal oil production of 167,942 bbl/d was strong and at the high end of the Company's previously issued guidance of 157,000 to 172,000 bbl/d.

Pelican Lake heavy crude oil production before royalties averaged 59,013 bbl/d for the fourth quarter of 2019 compared with 62,428 bbl/d for the fourth quarter of 2018 and 60,146 bbl/d for the third quarter of 2019.

Annual 2019 crude oil and NGLs production before royalties, including thermal oil, was within the Company's previously issued guidance of 388,000 to 423,000 bbl/d.

Natural gas production before royalties for the year ended December 31, 2019 decreased 3% to 1,443 MMcf/d from 1,490 MMcf/d for the year ended December 31, 2018. Natural gas production for the fourth quarter of 2019 averaged 1,411 MMcf/d, comparable with 1,441 MMcf/d for the fourth quarter of 2018, and 1,425 MMcf/d for the third quarter of 2019. The decrease in natural gas production for the year ended December 31, 2019 from the year ended December 31, 2018 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities due to low natural gas prices.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the year ended December 31, 2019 of 395,133 bbl/d decreased 7% from 426,190 bbl/d for the year ended December 31, 2018. SCO production for the fourth quarter of 2019 decreased 20% to average 357,856 bbl/d from 447,048 bbl/d for the fourth quarter of 2018 and decreased 17% from 432,203 bbl/d for the third quarter of 2019.

The decrease in production for the year ended December 31, 2019 from the year ended December 31, 2018 primarily reflected the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with the unplanned maintenance at the non-operated Scotford Upgrader and at Horizon in the first half of the year. The decrease in production in the fourth quarter of 2019 from the fourth quarter of 2018 and third quarter of 2019 primarily reflected the impact of the completion of the planned turnaround and a proactive piping replacement at Horizon in the fourth quarter of 2019. Annual 2019 SCO production was below the Company's previously issued guidance of 405,000 to 415,000 bbl/d. Production in 2019 was impacted by the Government of Alberta mandated production curtailments that came into effect on January 1, 2019.

North Sea

North Sea crude oil production before royalties for the year ended December 31, 2019 of 27,919 bbl/d increased 16% from 23,965 bbl/d for the year ended December 31, 2018. North Sea crude oil production for the fourth quarter of 2019 increased 46% to 30,860 bbl/d from 21,071 bbl/d for the fourth quarter of 2018 and increased 12% from 27,454 bbl/d for the third quarter of 2019. The increase in production for the three months and year ended December 31, 2019 from the comparable periods in 2018 primarily reflected volumes from new wells. The increase in production in the fourth quarter of 2019 from the third quarter of 2019 was primarily due to planned turnaround activities in the third quarter of 2019.

Offshore Africa

Offshore Africa crude oil production before royalties for the year ended December 31, 2019 increased 9% to 21,371 bbl/d from 19,662 bbl/d for the year ended December 31, 2018. Offshore Africa crude oil production for the fourth quarter of 2019 of 18,495 bbl/d decreased 17% from 22,185 bbl/d for the fourth quarter of 2018 and decreased 13% from 21,227 bbl/d for the third quarter of 2019. The increase in production for the year ended December 31, 2019 from the year ended December 31, 2018 primarily reflected volumes from new wells drilled in 2018 and the first quarter of 2019 at Baobab, partially offset by the cessation of production at the Olowi field, Gabon in December 2018 and natural field declines. The decrease in production for the fourth quarter of 2019 from the fourth quarter of 2018 and the third quarter of 2019 was primarily due to restricted production as a result of gas export riser maintenance activities at Baobab, as well as natural field declines.

International Guidance

Annual 2019 International crude oil production of 49,290 bbl/d was strong and at the high end of the Company's previously issued guidance of 46,000 to 50,000 bbl/d.

International Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018
North Sea	**344,726**	871,362	71,832
Offshore Africa	**519,504**	309,443	404,475
	864,230	1,180,805	476,307

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 49.60**	$ 55.19	$ 25.95	**$ 55.08**	$ 46.92
Transportation	**3.53**	3.69	2.94	**3.48**	3.08
Realized sales price, net of transportation	**46.07**	51.50	23.01	**51.60**	43.84
Royalties	**6.03**	6.02	0.92	**6.08**	5.08
Production expense	**12.46**	13.25	16.93	**13.81**	15.69
Netback	**$ 27.58**	$ 32.23	$ 5.16	**$ 31.71**	$ 23.07
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.64**	$ 1.64	$ 3.46	**$ 2.34**	$ 2.61
Transportation	**0.43**	0.40	0.42	**0.42**	0.47
Realized sales price, net of transportation	**2.21**	1.24	3.04	**1.92**	2.14
Royalties	**0.11**	0.01	0.10	**0.08**	0.08
Production expense	**1.17**	1.12	1.32	**1.22**	1.36
Netback	**$ 0.93**	$ 0.11	$ 1.62	**$ 0.62**	$ 0.70
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 39.20**	$ 40.36	$ 24.04	**$ 40.50**	$ 34.62
Transportation	**3.24**	3.27	2.77	**3.14**	2.96
Realized sales price, net of transportation	**35.96**	37.09	21.27	**37.36**	31.66
Royalties	**4.37**	4.07	0.80	**4.09**	3.27
Production expense	**10.79**	11.11	13.51	**11.49**	12.71
Netback	**$ 20.80**	$ 21.91	$ 6.96	**$ 21.78**	$ 15.68

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

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

PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 46.06**	$ 51.51	$ 17.03	**$ 51.43**	$ 41.82
North Sea	**$ 87.76**	$ 83.64	$ 78.45	**$ 86.76**	$ 87.41
Offshore Africa	**$ 70.73**	$ 82.97	$ 81.15	**$ 83.68**	$ 90.95
Average	**$ 49.60**	$ 55.19	$ 25.95	**$ 55.08**	$ 46.92
Natural gas ($/Mcf) (1) (2)					
North America	**$ 2.52**	$ 1.51	$ 3.23	**$ 2.18**	$ 2.33
North Sea	**$ 5.10**	$ 4.67	$ 14.09	**$ 6.52**	$ 12.08
Offshore Africa	**$ 8.58**	$ 7.08	$ 7.32	**$ 7.41**	$ 7.34
Average	**$ 2.64**	$ 1.64	$ 3.46	**$ 2.34**	$ 2.61
Average ($/BOE) (1) (2)	**$ 39.20**	$ 40.36	$ 24.04	**$ 40.50**	$ 34.62

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

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

North America

North America realized crude oil prices increased 23% to average $51.43 per bbl for the year ended December 31, 2019 from $41.82 per bbl for the year ended December 31, 2018. North America realized crude oil prices averaged $46.06 per bbl for the fourth quarter of 2019, an increase of 170% compared with $17.03 per bbl for the fourth quarter of 2018, and a decrease of 11% compared with $51.51 per bbl for the third quarter of 2019. The increase in realized crude oil prices for the three months and year ended December 31, 2019 from the comparable periods in 2018 was primarily due to the narrowing of the WCS Heavy Differential as a result of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The decrease in realized crude oil prices in the fourth quarter of 2019 from the third quarter of 2019 primarily reflected the widening of the WCS Heavy Differential due to seasonality. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2019 contributed approximately 178,800 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 6% to average $2.18 per Mcf for the year ended December 31, 2019 from $2.33 per Mcf for the year ended December 31, 2018. North America realized natural gas prices decreased 22% to average $2.52 per Mcf for the fourth quarter of 2019 from $3.23 per Mcf for the fourth quarter of 2018, and increased 67% from $1.51 per Mcf for the third quarter of 2019. The decrease in realized natural gas prices for the three months and year ended December 31, 2019 from the comparable periods in 2018 primarily reflected increased production levels in North America and the impact of seasonal weather conditions. The increase in realized natural gas prices in the fourth quarter of 2019 from the third quarter of 2019 primarily reflected additional egress capability, seasonal demand factors, and the impact of the TC Energy Temporary Service Protocol.

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

	Three Months Ended		
(Quarterly Average)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 47.32**	$ 48.21	$ 34.62
Pelican Lake heavy crude oil ($/bbl)	**$ 51.66**	$ 56.75	$ 12.40
Primary heavy crude oil ($/bbl)	**$ 49.72**	$ 55.47	$ 11.33
Bitumen (thermal oil) ($/bbl)	**$ 42.93**	$ 49.80	$ 7.70
Natural gas ($/Mcf)	**$ 2.52**	$ 1.51	$ 3.23

(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 of $86.76 per bbl for the year ended December 31, 2019 were comparable with $87.41 per bbl for the year ended December 31, 2018. North Sea realized crude oil prices increased 12% to average $87.76 per bbl for the fourth quarter of 2019 from $78.45 per bbl for the fourth quarter of 2018 and increased 5% from $83.64 per bbl for the third quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months ended December 31, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 8% to average $83.68 per bbl for the year ended December 31, 2019 from $90.95 per bbl for the year ended December 31, 2018. Offshore Africa realized crude oil prices decreased 13% to average $70.73 per bbl for the fourth quarter of 2019 from $81.15 per bbl for the fourth quarter of 2018 and decreased 15% from $82.97 per bbl for the third quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three months and year ended December 31, 2019 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 6.52**	$ 6.50	$ 0.82	**$ 6.56**	$ 5.36
North Sea	**$ 0.13**	$ 0.17	$ 0.18	**$ 0.16**	$ 0.22
Offshore Africa	**$ 4.60**	$ 4.43	$ 3.00	**$ 4.74**	$ 6.00
Average	**$ 6.03**	$ 6.02	$ 0.92	**$ 6.08**	$ 5.08
Natural gas ($/Mcf) (1)					
North America	**$ 0.11**	$ 0.01	$ 0.09	**$ 0.07**	$ 0.07
Offshore Africa	**$ 0.39**	$ 0.63	$ 0.80	**$ 0.63**	$ 1.00
Average	**$ 0.11**	$ 0.01	$ 0.10	**$ 0.08**	$ 0.08
Average ($/BOE) (1)	**$ 4.37**	$ 4.07	$ 0.80	**$ 4.09**	$ 3.27

(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, 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 13% of product sales for the year ended December 31, 2019 compared with 14% of product sales for the year ended December 31, 2018. Crude oil and NGLs royalty rates averaged approximately 14% of product sales for the fourth quarter of 2019 compared with 6% for the fourth quarter of 2018 and 13% for the third quarter of 2019. The increase in royalty rates for the fourth quarter of 2019 from the fourth quarter of 2018 primarily reflected higher realized crude oil prices in the fourth quarter of 2019.

Natural gas royalty rates averaged approximately 3% of product sales for the year ended December 31, 2019 compared with 4% of product sales for the year ended December 31, 2018. Natural gas royalty rates averaged approximately 4% of product sales for the fourth quarter of 2019 compared with 3% for the fourth quarter of 2018 and 1% for the third quarter of 2019, reflecting higher realized natural gas prices in the fourth quarter of 2019 compared with the third quarter of 2019.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 6% for the year ended December 31, 2019, compared with 7% of product sales for the year ended December 31, 2018. Royalty rates as a percentage of product sales averaged approximately 6% for the fourth quarter of 2019, compared with 4% of product sales for the fourth quarter of 2018 and 6% for the third quarter of 2019. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2019	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 10.74**	$ 11.86	$ 13.36	**$ 12.41**	$ 13.48
North Sea	**$ 33.67**	$ 37.11	$ 44.20	**$ 36.39**	$ 39.89
Offshore Africa	**$ 16.75**	$ 11.06	$ 32.15	**$ 11.21**	$ 26.34
Average	**$ 12.46**	$ 13.25	$ 16.93	**$ 13.81**	$ 15.69
Natural gas ($/Mcf) (1)					
North America	**$ 1.11**	$ 1.07	$ 1.23	**$ 1.16**	$ 1.25
North Sea (2)	**$ 3.25**	$ 3.08	$ 5.76	**$ 3.40**	$ 5.29
Offshore Africa (2)	**$ 3.19**	$ 2.78	$ 3.00	**$ 2.60**	$ 2.76
Average	**$ 1.17**	$ 1.12	$ 1.32	**$ 1.22**	$ 1.36
Average ($/BOE) (1)	**$ 10.79**	$ 11.11	$ 13.51	**$ 11.49**	$ 12.71

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

(2) North Sea and Offshore Africa natural gas production expense for the year ended December 31, 2019 reflected a decrease of $23 million ($2.66 per Mcf) and $5 million ($0.55 per Mcf) respectively, related to the adoption of IFRS 16.

North America

North America crude oil and NGLs production expense for the year ended December 31, 2019 averaged $12.41 per bbl, a decrease of 8% from $13.48 per bbl for the year ended December 31, 2018. North America crude oil and NGLs production expense for the fourth quarter of 2019 of $10.74 per bbl decreased 20% from $13.36 per bbl for the fourth quarter of 2018 and decreased 9% from $11.86 per bbl for the third quarter of 2019. The decrease in crude oil and NGLs production expense per barrel for the three months and year ended December 31, 2019 from the comparable periods primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose in the fourth quarter of 2019, offsetting the impact of higher fuel and energy costs during the quarter. The Company continues to focus on cost control and achieving efficiencies across the entire asset base.

North America crude oil and NGLs production expense for the year ended December 31, 2019 also reflected a decrease of $22 million ($0.15 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for the year ended December 31, 2019 averaged $1.16 per Mcf, a decrease of 7% from $1.25 per Mcf for the year ended December 31, 2018. North America natural gas production expense for the fourth quarter of 2019 of $1.11 per Mcf decreased 10% from $1.23 per Mcf for the fourth quarter of 2018 and increased 4% from $1.07 per Mcf for the third quarter of 2019. Changes in production expense for the three months and year ended December 31, 2019 from the comparable periods primarily reflected the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control, and achieving efficiencies across the entire asset base.

North America natural gas production expense for the year ended December 31, 2019 also reflected a decrease of $6 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea

North Sea crude oil production expense for the year ended December 31, 2019 decreased 9% to $36.39 per bbl from $39.89 per bbl for the year ended December 31, 2018. North Sea crude oil production expense for the fourth quarter of 2019 of $33.67 per bbl decreased 24% from $44.20 per bbl for the fourth quarter of 2018 and decreased 9% from $37.11 per bbl for the third quarter of 2019. The decrease in crude oil production expense for the three months and year ended December 31, 2019 from comparable periods reflected increased production volumes, together with fluctuations in the Canadian dollar.

North Sea crude oil production expense for the year ended December 31, 2019 also reflected a decrease of $21 million ($2.10 per bbl) related to the adoption of IFRS 16.

Offshore Africa

Offshore Africa crude oil production expense for the year ended December 31, 2019 was $11.21 per bbl compared with $26.34 per bbl for the year ended December 31, 2018. Offshore Africa crude oil production expense for the fourth quarter of 2019 averaged $16.75 per bbl compared with $32.15 per bbl for the fourth quarter of 2018 and $11.06 per bbl for the third quarter of 2019. Crude oil production expense in 2019 reflected the cessation of production at the Olowi field, Gabon in December 2018.

Crude oil production expense for the three months and year ended December 31, 2019 and the comparable periods also reflected the timing of liftings from various fields that have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

Offshore Africa crude oil production expense for the year ended December 31, 2019 also reflected a decrease of $20 million ($2.56 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Expense	**$ 1,083**	$ 1,021	$ 929	**$ 3,876**	$ 3,590
$/BOE (1)	**$ 14.98**	$ 14.89	$ 15.50	**$ 15.22**	$ 15.12

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

Depletion, depreciation and amortization expense for the year ended December 31, 2019 of $15.22 per BOE was comparable with $15.12 per BOE for the year ended December 31, 2018. Depletion, depreciation and amortization expense for the fourth quarter of 2019 of $14.98 per BOE decreased 3% from $15.50 per BOE for the fourth quarter of 2018 and was comparable with $14.89 per BOE for the third quarter of 2019.

The decrease in depletion, depreciation and amortization expense per BOE for the fourth quarter of 2019 from the fourth quarter of 2018 primarily reflected increased production volumes subject to lower depletion rates from the Devon assets acquired in the second quarter of 2019. Depletion, depreciation and amortization expense for the year ended December 31, 2019 also reflected an increase of $168 million ($0.66 per BOE) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Expense	**$ 36**	$ 34	$ 31	**$ 129**	$ 125
$/BOE (1)	**$ 0.49**	$ 0.51	$ 0.52	**$ 0.51**	$ 0.53

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2019 decreased 4% to $0.51 per BOE from $0.53 per BOE for the year ended December 31, 2018. Asset retirement obligation accretion expense for the fourth quarter of 2019 of $0.49 per BOE decreased 6% from $0.52 per BOE for the fourth quarter of 2018, and decreased 4% from $0.51 per BOE for the third quarter of 2019. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Production in the fourth quarter of 2019 averaged 357,856 bbl/d, reflecting the impact of the completion of the planned turnaround and a proactive piping replacement in one of the hydrogen units at Horizon. Production levels during the quarter also continued to be impacted by the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Through continuous focus on cost control and efficiencies, the Company has achieved a decrease of $124 million (4%) in adjusted production costs, excluding natural gas costs for the year ended December 31, 2019 of $3,032 million ($20.89 per bbl), from $3,156 million ($20.39 per bbl) for the year ended December 31, 2018.

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

	Three Months Ended			Year Ended	
($/bbl) [1]	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
SCO realized sales price [2]	**$ 68.67**	$ 71.60	$ 42.73	**$ 70.18**	$ 68.61
Bitumen value for royalty purposes [3]	**$ 44.88**	$ 51.70	$ 29.93	**$ 50.79**	$ 40.02
Bitumen royalties [4]	**$ 3.47**	$ 3.76	$ 2.03	**$ 3.31**	$ 3.09
Transportation	**$ 1.33**	$ 1.16	$ 1.56	**$ 1.29**	$ 1.61

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price averaged $70.18 per bbl for the year ended December 31, 2019, comparable with $68.61 per bbl for the year ended December 31, 2018. For the fourth quarter of 2019, the realized sales price increased 61% to $68.67 per bbl from $42.73 per bbl for the fourth quarter of 2018 and decreased 4% from $71.60 per bbl for the third quarter of 2019. The increase in the realized SCO sales price for the fourth quarter of 2019 from the fourth quarter of 2018 was primarily due to the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The decrease in realized SCO prices in the fourth quarter of 2019 from the third quarter of 2019 primarily reflected the movement in WTI and SCO benchmark pricing.

Transportation expense averaged $1.29 per bbl for the year ended December 31, 2019, compared with $1.61 per bbl for the year ended December 31, 2018. Transportation expense averaged $1.33 per bbl for the fourth quarter of 2019, compared with $1.56 per bbl for the fourth quarter of 2018 and $1.16 per bbl for the third quarter of 2019. Transportation expense for the year ended December 31, 2019 reflected a decrease of $78 million ($0.53 per bbl) related to the adoption of IFRS 16.

ADJUSTED PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Production costs	**$ 856**	$ 784	$ 797	**$ 3,276**	$ 3,367
Less: costs incurred during turnaround periods	**(71)**	(48)	—	**(119)**	(109)
Adjusted production costs	**$ 785**	$ 736	$ 797	**$ 3,157**	$ 3,258
Adjusted production costs, excluding natural gas costs	**$ 743**	$ 721	$ 773	**$ 3,032**	$ 3,156
Natural gas costs	**42**	15	24	**125**	102
Adjusted production costs	**$ 785**	$ 736	$ 797	**$ 3,157**	$ 3,258

($/bbl) (1)	Three Months Ended **Dec 31 2019**	 Sep 30 2019	 Dec 31 2018	Year Ended **Dec 31 2019**	 Dec 31 2018
Adjusted production costs, excluding natural gas costs	**$ 21.79**	$ 18.43	$ 19.37	**$ 20.89**	$ 20.39
Natural gas costs	**1.23**	0.39	0.60	**0.86**	0.66
Adjusted production costs	**$ 23.02**	$ 18.82	$ 19.97	**$ 21.75**	$ 21.05
Sales (bbl/d)	**370,468**	425,140	433,970	**397,735**	424,112

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

Production costs for the three months and year ended December 31, 2019 were $25.09 per bbl and $22.56 per bbl, respectively. Adjusted production costs for the year ended December 31, 2019 increased 3% to $21.75 per bbl from $21.05 per bbl for the year ended December 31, 2018. Adjusted production costs for the fourth quarter of 2019 averaged $23.02 per bbl, an increase of 15% from $19.97 per bbl for the fourth quarter of 2018 and an increase of 22% from $18.82 per bbl for the third quarter of 2019.

The increase in adjusted production costs for the three months and year ended December 31, 2019 from comparable periods primarily reflected reduced production volumes due to the impact of a proactive piping replacement in one of the hydrogen units at Horizon, together with increased natural gas costs.

Adjusted production costs for the year ended December 31, 2019 also reflected a decrease of $29 million ($0.20 per bbl) related to the adoption of IFRS 16.

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

($ millions, except per bbl amounts)	Three Months Ended **Dec 31 2019**	 Sep 30 2019	 Dec 31 2018	Year Ended **Dec 31 2019**	 Dec 31 2018
Expense	**$ 464**	$ 401	$ 396	**$ 1,656**	$ 1,557
Less: depreciation incurred during turnaround period	**(46)**	(22)	—	**(69)**	(56)
Adjusted depletion, depreciation and amortization	**$ 418**	$ 379	$ 396	**$ 1,587**	$ 1,501
$/bbl (1)	**$ 12.25**	$ 9.68	$ 9.92	**$ 10.94**	$ 9.70

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

Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2019 increased 13% to $10.94 per bbl from $9.70 per bbl for the year ended December 31, 2018. Adjusted depletion, depreciation and amortization expense for the fourth quarter of 2019 of $12.25 per bbl increased 23% from $9.92 per bbl for the fourth quarter of 2018, and increased 27% from $9.68 per bbl for the third quarter of 2019.

The increase in adjusted depletion, depreciation and amortization expense for the three months and year ended December 31, 2019 from the comparable periods primarily reflected the impact of fluctuations in sales volumes from different underlying operations, a proactive piping replacement at Horizon in the fourth quarter of 2019, along with the adoption of IFRS 16. Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2019 reflected an increase of $92 million ($0.63 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended **Dec 31 2019**	 Sep 30 2019	 Dec 31 2018	Year Ended **Dec 31 2019**	 Dec 31 2018
Expense	**$ 14**	$ 16	$ 15	**$ 61**	$ 61
$/bbl (1)	**$ 0.44**	$ 0.38	$ 0.38	**$ 0.42**	$ 0.40

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

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

Asset retirement obligation accretion expense for the year ended December 31, 2019 increased 5% to $0.42 per bbl from $0.40 per bbl for the year ended December 31, 2018. Asset retirement obligation accretion expense of $0.44 per bbl for the fourth quarter of 2019 increased 16% from $0.38 per bbl for the fourth quarter of 2018 and the third quarter of 2019. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Revenue	**$ 26**	$ 21	$ 24	**$ 88**	$ 102
Less:					
Production expense	**5**	4	5	**20**	21
Depreciation	**3**	4	3	**14**	14
Equity loss from investment	**73**	88	—	**287**	5
Segment earnings (loss) before taxes	**$ (55)**	$ (75)	$ 16	**$ (233)**	$ 62

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

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing SCO into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. Design modifications to the reactor burners in the gasifier unit are ongoing and have continued through the first quarter of 2020. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the syndicated credit facility.

The Company recognized an equity loss from Redwater Partnership of $287 million for the year ended December 31, 2019 (year ended December 31, 2018 – loss of $5 million), reducing the carrying value in Redwater Partnership to $nil. The unrecognized share of losses from Redwater Partnership for the year ended December 31, 2019 was $59 million.

The equity loss for the year ended December 31, 2019 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
Expense	**$ 95**	$ 95	$ 91	**$ 344**	$ 325
$/BOE (1)	**$ 0.90**	$ 0.88	$ 0.91	**$ 0.86**	$ 0.83

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

Administration expense per BOE for the year ended December 31, 2019 increased 4% to $0.86 per BOE from $0.83 per BOE for the year ended December 31, 2018. Administration expense for the fourth quarter of 2019 of $0.90 per BOE was comparable with $0.91 per BOE for the fourth quarter of 2018 and $0.88 per BOE for the third quarter of 2019. Administration expense per BOE increased for the year ended December 31, 2019 from the year ended December 31, 2018 primarily due to higher personnel costs, including those associated with the acquisition of assets from Devon. Administration expense for the year ended December 31, 2019 also reflected a decrease of $23 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
Expense (recovery)	**$ 161**	$ 7	$ (148)	**$ 223**	$ (146)

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 PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recorded a $223 million share-based compensation expense for the year ended December 31, 2019, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation expense for the year ended December 31, 2019 was $49 million related to PSUs granted to certain executive employees (December 31, 2018 – $8 million). For the year ended December 31, 2019, the Company charged $5 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (December 31, 2018 – $19 million recovered).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
Expense, gross	**$ 225**	$ 239	$ 198	**$ 889**	$ 808
Less: capitalized interest	**8**	8	19	**53**	69
Expense, net	**$ 217**	$ 231	$ 179	**$ 836**	$ 739
$/BOE (1)	**$ 2.04**	$ 2.14	$ 1.78	**$ 2.09**	$ 1.88
Average effective interest rate	**3.9%**	3.9%	4.1%	**4.0%**	3.9%

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

Gross interest and other financing expense for the three months and year ended December 31, 2019 increased from the comparable periods in 2018 primarily due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Gross interest and other financing expense for the fourth quarter of 2019 was lower than the third quarter of 2019 primarily due to lower average debt levels in the fourth quarter of 2019. Capitalized interest of $53 million for the year ended December 31, 2019 was related to Kirby North and residual project activities at Horizon.

Net interest and other financing expense per BOE for the year ended December 31, 2019 increased 11% to $2.09 per BOE from $1.88 per BOE for the year ended December 31, 2018. Net interest and other financing expense per BOE for the fourth quarter of 2019 increased 15% to $2.04 per BOE from $1.78 per BOE for the fourth quarter of 2018 and decreased 5% from $2.14 per BOE for the third quarter of 2019. The increase in net interest and other financing expense per BOE for the three months and year ended December 31, 2019 from the comparable periods in 2018 primarily reflected the adoption of IFRS 16, together with lower capitalized interest and higher average debt levels in 2019. Net interest and other financing expense per BOE for the fourth quarter of 2019 decreased from the third quarter of 2019 primarily due to lower average debt levels in the fourth quarter. Net interest and other financing expense for the year ended December 31, 2019 reflected an increase of $70 million ($0.18 per BOE) related to the adoption of IFRS 16.

The Company's average effective interest rate for the fourth quarter of 2019 decreased from the fourth quarter of 2018 primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program.

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 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Crude oil and NGLs financial instruments	**$ —**	$ 11	$ (27)	**$ 52**	$ (27)
Natural gas financial instruments	**6**	(4)	2	**(1)**	5
Foreign currency contracts	**5**	(8)	(20)	**13**	(77)
Realized loss (gain)	**11**	(1)	(45)	**64**	(99)
Crude oil and NGLs financial instruments	**—**	(7)	41	**(17)**	16
Natural gas financial instruments	**7**	7	(6)	**15**	(4)
Foreign currency contracts	**10**	(2)	(8)	**15**	(47)
Unrealized loss (gain)	**17**	(2)	27	**13**	(35)
Net loss (gain)	**$ 28**	$ (3)	$ (18)	**$ 77**	$ (134)

During the year ended December 31, 2019, net realized risk management losses were related to the settlement of crude oil and NGLs financial instruments and foreign currency contracts. The Company recorded a net unrealized loss of $13 million ($14 million after-tax) on its risk management activities for the year ended December 31, 2019, including an unrealized loss of $17 million ($16 million after-tax) for the fourth quarter of 2019 (September 30, 2019 – unrealized gain of $2 million, $2 million after-tax; December 31, 2018 – unrealized loss of $27 million, $17 million after-tax).

Further details related to outstanding derivative financial instruments at December 31, 2019 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Net realized (gain) loss	**$ (4)**	$ (14)	$ (2)	**$ (22)**	$ 121
Net unrealized (gain) loss	**(225)**	129	548	**(548)**	706
Net (gain) loss (1)	**$ (229)**	$ 115	$ 546	**$ (570)**	$ 827

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

The net realized foreign exchange gain for the year ended December 31, 2019 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the year ended December 31, 2019 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented included the impact of cross currency swaps (three months ended December 31, 2019 – unrealized loss of $29 million, September 30, 2019 – unrealized gain of $16 million, December 31, 2018 – unrealized gain of $76 million; year ended December 31, 2019 – unrealized loss of $71 million, December 31, 2018 – unrealized gain of $118 million). The US/Canadian dollar exchange rate at December 31, 2019 was US$0.7713 (September 30, 2019 – US$0.7551, December 31, 2018 – US$0.7328).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
North America [1]	**$ (20)**	$ 133	$ (254)	**$ 354**	$ 312
North Sea	**40**	15	8	**112**	28
Offshore Africa	**7**	14	11	**44**	54
PRT [2] – North Sea	**—**	(4)	—	**(89)**	(29)
Other taxes	**4**	3	1	**13**	9
Current income tax expense (recovery)	**31**	161	(234)	**434**	374
Deferred corporate income tax expense (recovery)	**194**	176	112	**(895)**	540
Deferred PRT [2] – North Sea	**—**	—	(1)	**1**	17
Deferred income tax expense (recovery)	**194**	176	111	**(894)**	557
	225	337	(123)	**(460)**	931
Income tax rate and other legislative changes	**—**	—	—	**1,618**	—
	$ 225	$ 337	$ (123)	**$ 1,158**	$ 931
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**26%**	22%	33%	**25%**	21%

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

(2) Petroleum Revenue Tax

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

The effective income tax rate for the three months and year ended December 31, 2019 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea for the year ended December 31, 2019 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

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

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Dec 31 2019	Sep 30 2019	Dec 31 2018	Year Ended Dec 31 2019	Dec 31 2018
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ —**	$ (2)	$ (113)	**$ 90**	$ (74)
Net expenditures	**—**	5	18	**74**	122
Total Exploration and Evaluation	**—**	3	(95)	**164**	48
Property, Plant and Equipment					
Net property acquisitions [2]	**20**	30	1	**3,208**	98
Well drilling, completion and equipping	**169**	181	359	**775**	1,446
Production and related facilities	**238**	232	365	**1,028**	1,262
Capitalized interest and other	**15**	14	32	**81**	106
Total Property, Plant and Equipment	**442**	457	757	**5,092**	2,912
Total Exploration and Production	**442**	460	662	**5,256**	2,960
Oil Sands Mining and Upgrading					
Project costs [3]	**121**	133	178	**436**	438
Sustaining capital	**334**	249	235	**933**	665
Turnaround costs	**57**	36	12	**118**	112
Acquisitions of Exploration and Evaluation assets [4]	**—**	—	—	**—**	218
Capitalized interest and other	**9**	10	(8)	**38**	14
Total Oil Sands Mining and Upgrading	**521**	428	417	**1,525**	1,447
Midstream and Refining	**1**	4	2	**10**	13
Abandonments [5]	**84**	63	93	**296**	290
Head office	**8**	8	7	**34**	21
Total net capital expenditures	**$ 1,056**	$ 963	$ 1,181	**$ 7,121**	$ 4,731
By segment					
North America [2]	**$ 330**	$ 365	$ 604	**$ 4,831**	$ 2,671
North Sea	**63**	55	58	**196**	131
Offshore Africa	**49**	40	—	**229**	158
Oil Sands Mining and Upgrading [4]	**521**	428	417	**1,525**	1,447
Midstream and Refining	**1**	4	2	**10**	13
Abandonments [5]	**84**	63	93	**296**	290
Head office	**8**	8	7	**34**	21
Total	**$ 1,056**	$ 963	$ 1,181	**$ 7,121**	$ 4,731

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

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

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

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

(5) 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 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Cash flows used in investing activities	***$ 854***	*$ 908*	*$ 1,042*	***$ 7,255***	*$ 4,814*
Net change in non-cash working capital (1)	***118***	*(8)*	*46*	***(430)***	*(345)*
Investment in other long-term assets	**—**	—	—	**—**	*(28)*
Abandonment expenditures (2)	***84***	*63*	*93*	***296***	*290*
Net capital expenditures	***$ 1,056***	*$ 963*	*$ 1,181*	***$ 7,121***	*$ 4,731*

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

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

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

Net capital expenditures for the year ended December 31, 2019 were $7,121 million, which included $3,217 million of cash consideration paid to acquire assets from Devon in the second quarter of 2019, as compared with $4,731 million for the year ended December 31, 2018. Net capital expenditures for the fourth quarter of 2019 were $1,056 million, compared with $1,181 million for the fourth quarter of 2018 and $963 million for the third quarter of 2019.

2020 Capital Budget

On December 4, 2019, the Company announced its 2020 Capital Budget targeting a base capital program of $4,050 million. Subsequently, due to the volatile state of the current crude oil price environment, the Company reduced its capital budget to $3,950 million, demonstrating the Company's ability to be nimble. This reduction in capital expenditures will have no impact on 2020 production volumes.

Drilling Activity (1)

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2019**	Sep 30 2019	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Net successful natural gas wells	**4**	5	3	**19**	18
Net successful crude oil wells (2)	**12**	36	102	**86**	483
Dry wells	**—**	—	2	**3**	9
Stratigraphic test / service wells	**89**	23	91	**447**	615
Total	**105**	64	198	**555**	1,125
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	98%	**97%**	98%

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

(2) Includes bitumen wells.

North America

During the fourth quarter of 2019, the Company targeted 4 net natural gas wells, 6 net primary heavy crude oil wells, 3 net bitumen (thermal oil) wells and 3 net light crude oil wells.

North Sea

During the fourth quarter of 2019, the Company completed 2 gross injection wells (1.9 on a net basis) in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Dec 31 2019**		Sep 30 2019		Dec 31 2018
Working capital (1)	**$**	**241**	$	859	$	(601)
Long-term debt (2) (3)	**$**	**20,982**	$	22,489	$	20,623
Less: cash and cash equivalents		**139**		176		101
Long-term debt, net	**$**	**20,843**	$	22,313	$	20,522
Share capital	**$**	**9,533**	$	9,314	$	9,323
Retained earnings		**25,424**		25,382		22,529
Accumulated other comprehensive income		**34**		98		122
Shareholders' equity	**$**	**34,991**	$	34,794	$	31,974
Debt to book capitalization (3) (4)		**37.3%**		39.1%		39.1%
Debt to market capitalization (3) (5)		**29.5%**		34.8%		34.1%
After-tax return on average common shareholders' equity (6)		**16.1%**		12.1%		8.0%
After-tax return on average capital employed (3) (7)		**10.9%**		8.4%		5.9%

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

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Reviewing the Company's borrowing capacity:
    - During the fourth quarter of 2019, the Company fully repaid and cancelled the $1,000 million non-revolving term credit facility scheduled to mature in May 2020. Previously, in the third quarter of 2019, the Company repaid and cancelled $800 million of this non-revolving term credit facility.
    - During the fourth quarter of 2019, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.
    - During the fourth quarter of 2019, the Company reduced the £15 million demand credit facility related to the Company's North Sea operations, to £5 million.

- During the fourth quarter of 2019, the Company extended the $2,425 million revolving syndicated credit facility scheduled to mature in June 2021 to June 2023. Previously, in the second quarter of 2019, the Company extended $330 million of this revolving syndicated credit facility originally due June 2019 to June 2021.
- Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- During the second quarter of 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
- Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2019, the non-revolving term credit facilities were fully drawn.
- During the fourth quarter of 2019, the Company repaid $500 million of 2.60% medium-term notes. During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- In July 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021, and replacing the Company's previous base shelf prospectuses, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

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

As at December 31, 2019, the Company had in place revolving bank credit facilities of $4,959 million, of which $4,737 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at December 31, 2019, the Company had total US dollar denominated debt with a carrying amount of $15,102 million (US$11,649 million), before transaction costs and original issue discounts. This included $6,545 million (US$5,049 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,999 million). The fixed repayment amount of these hedging instruments is $6,429 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $116 million to $14,986 million as at December 31, 2019.

Net long-term debt was $20,843 million at December 31, 2019, resulting in a debt to book capitalization ratio of 37.3% (December 31, 2018 – 39.1%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at December 31, 2019 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, 2019, the Company was in compliance with this covenant.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters. As at December 31, 2019, 140,000 MMbtu/d of currently forecasted natural gas volumes were hedged using AECO basis swaps for January 2020 to March 2020. Additionally, at December 31, 2019, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October

2020. Further details related to the Company's commodity derivative financial instruments outstanding at December 31, 2019 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

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

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Long-term debt (1)	$	2,391	$	1,552	$	8,921	$	8,226
Other long-term liabilities (2)	$	370	$	196	$	436	$	1,014
Interest and other financing expense (3)	$	881	$	813	$	1,771	$	4,856

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows: less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter, $1,014 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2019.

Share Capital

As at December 31, 2019, there were 1,186,857,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 47,646,000 stock options outstanding. As at March 3, 2020, the Company had 1,181,337,000 common shares outstanding and 53,611,000 stock options outstanding.

On March 4, 2020, the Board of Directors approved an increase in the quarterly dividend to $0.425 per common share, beginning with the dividend payable on April 1, 2020. On March 6, 2019, the Board of Directors approved an increase in the quarterly dividend to $0.375 per common share (previous quarterly dividend rate of $0.335 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

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

For the year ended December 31, 2019, the Company purchased for cancellation 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,600,000 common shares at a weighted average price of $39.41 per common share for a total cost of $260 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 (1):

($ millions)		2020		2021		2022		2023		2024		Thereafter
Product transportation (2) (3)	$	730	$	722	$	637	$	726	$	699	$	7,907
North West Redwater Partnership service toll (4)	$	133	$	167	$	157	$	164	$	156	$	2,815
Offshore vessels and equipment	$	69	$	63	$	9	$	—	$	—	$	—
Field equipment and power	$	27	$	21	$	20	$	21	$	20	$	249
Other	$	26	$	20	$	17	$	17	$	17	$	30

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

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

(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(4) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 million of interest payable over the 30 year tolling period.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CHANGES IN ACCOUNTING POLICIES

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

IFRS 16 "Leases"

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

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

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

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

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

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

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

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

- Cash flow from operating activities and adjusted funds flow increased as the principal portions of lease payments, previously classified as cash flows from operating activities are now reported as cash flows used in financing activities;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and

- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the "Liquidity and Capital Resources" section of this MD&A.

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 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 prospectively adopted the amendments on January 1, 2020.

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 prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Based on inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note		**Dec 31 2019**		Dec 31 2018
ASSETS					
Current assets					
Cash and cash equivalents		**$**	**139**	$	101
Accounts receivable			**2,465**		1,148
Current income taxes receivable			**13**		—
Inventory			**1,152**		955
Prepaids and other			**174**		176
Investments	7		**490**		524
Current portion of other long-term assets	8		**54**		116
			4,487		3,020
Exploration and evaluation assets	4		**2,579**		2,637
Property, plant and equipment	5		**68,043**		64,559
Lease assets	6		**1,789**		—
Other long-term assets	8		**1,223**		1,343
		$	**78,121**	$	71,559
LIABILITIES					
Current liabilities					
Accounts payable		**$**	**816**	$	779
Accrued liabilities			**2,611**		2,356
Current income taxes payable			**—**		151
Current portion of long-term debt	9		**2,391**		1,141
Current portion of other long-term liabilities	6,10		**819**		335
			6,637		4,762
Long-term debt	9		**18,591**		19,482
Other long-term liabilities	6,10		**7,363**		3,890
Deferred income taxes			**10,539**		11,451
			43,130		39,585
SHAREHOLDERS' EQUITY					
Share capital	12		**9,533**		9,323
Retained earnings			**25,424**		22,529
Accumulated other comprehensive income	13		**34**		122
			34,991		31,974
		$	**78,121**	$	71,559

Commitments and contingencies (note 17).

Approved by the Board of Directors on March 4, 2020.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2019	Three Months Ended Dec 31 2018	Year Ended Dec 31 2019	Year Ended Dec 31 2018
Product sales	18	**$ 6,335**	$ 3,831	**$ 24,394**	$ 22,282
Less: royalties		**(434)**	(129)	**(1,523)**	(1,255)
Revenue		**5,901**	3,702	**22,871**	21,027
Expenses					
Production		**1,648**	1,627	**6,277**	6,464
Transportation, blending and feedstock		**1,416**	864	**4,699**	4,189
Depletion, depreciation and amortization	5,6	**1,550**	1,328	**5,546**	5,161
Administration		**95**	91	**344**	325
Share-based compensation	10	**161**	(148)	**223**	(146)
Asset retirement obligation accretion	10	**50**	46	**190**	186
Interest and other financing expense		**217**	179	**836**	739
Risk management activities	16	**28**	(18)	**77**	(134)
Foreign exchange (gain) loss		**(229)**	546	**(570)**	827
Gain on acquisition, disposition and revaluation of properties		**—**	(41)	**—**	(452)
Loss from investments	7,8	**143**	127	**293**	346
		5,079	4,601	**17,915**	17,505
Earnings (loss) before taxes		**822**	(899)	**4,956**	3,522
Current income tax expense (recovery)	11	**31**	(234)	**434**	374
Deferred income tax expense (recovery)	11	**194**	111	**(894)**	557
Net earnings (loss)		**$ 597**	$ (776)	**$ 5,416**	$ 2,591
Net earnings (loss) per common share					
Basic	15	**$ 0.50**	$ (0.64)	**$ 4.55**	$ 2.13
Diluted	15	**$ 0.50**	$ (0.64)	**$ 4.54**	$ 2.12

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Dec 31 2019	Three Months Ended Dec 31 2018	Year Ended Dec 31 2019	Year Ended Dec 31 2018
Net earnings (loss)	**$ 597**	$ (776)	**$ 5,416**	$ 2,591
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $1 million (2018 – $1 million) – three months ended; $13 million (2018 – $nil) – year ended	**2**	12	**99**	5
Reclassification to net earnings (loss), net of taxes of $nil million (2018 – $1 million) – three months ended; $5 million (2018 – $6 million) – year ended	**(5)**	(8)	**(41)**	(39)
	(3)	4	**58**	(34)
Foreign currency translation adjustment				
Translation of net investment	**(61)**	151	**(146)**	224
Other comprehensive income (loss), net of taxes	**(64)**	155	**(88)**	190
Comprehensive income (loss)	**$ 533**	$ (621)	**$ 5,328**	$ 2,781

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended **Dec 31 2019**	Dec 31 2018
Share capital	12		
Balance – beginning of year		**$ 9,323**	$ 9,109
Issued upon exercise of stock options		**360**	332
Previously recognized liability on stock options exercised for common shares		**53**	120
Purchase of common shares under Normal Course Issuer Bid		**(203)**	(238)
Balance – end of year		**9,533**	9,323
Retained earnings			
Balance – beginning of year		**22,529**	22,612
Net earnings		**5,416**	2,591
Dividends on common shares	12	**(1,783)**	(1,630)
Purchase of common shares under Normal Course Issuer Bid	12	**(738)**	(1,044)
Balance – end of year		**25,424**	22,529
Accumulated other comprehensive income	13		
Balance – beginning of year		**122**	(68)
Other comprehensive income (loss), net of taxes		**(88)**	190
Balance – end of year		**34**	122
Shareholders' equity		**$ 34,991**	$ 31,974

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Dec 31 2019	Three Months Ended Dec 31 2018	Year Ended Dec 31 2019	Year Ended Dec 31 2018
Operating activities					
Net earnings (loss)		**$ 597**	$ (776)	**$ 5,416**	$ 2,591
Non-cash items					
Depletion, depreciation and amortization		**1,550**	1,328	**5,546**	5,161
Share-based compensation		**161**	(148)	**223**	(146)
Asset retirement obligation accretion		**50**	46	**190**	186
Unrealized risk management loss (gain)		**17**	27	**13**	(35)
Unrealized foreign exchange (gain) loss		**(225)**	548	**(548)**	706
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**—**	146
Gain on acquisition, disposition and revaluation of properties		**—**	(41)	**—**	(452)
Loss from investments	7,8	**150**	134	**321**	374
Deferred income tax expense (recovery)		**194**	111	**(894)**	557
Other		**(8)**	(18)	**(109)**	(23)
Abandonment expenditures		**(84)**	(93)	**(296)**	(290)
Net change in non-cash working capital		**52**	279	**(1,033)**	1,346
Cash flows from operating activities		**2,454**	1,397	**8,829**	10,121
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	9	**(701)**	252	**2,025**	(1,595)
Repayment of medium-term notes	9	**(500)**	—	**(1,000)**	—
Repayment of US dollar debt securities		**—**	—	**—**	(1,236)
Payment of lease liabilities	6	**(64)**	—	**(237)**	—
Issue of common shares on exercise of stock options		**212**	12	**360**	332
Dividends on common shares		**(444)**	(406)	**(1,743)**	(1,562)
Purchase of common shares under Normal Course Issuer Bid		**(140)**	(408)	**(941)**	(1,282)
Cash flows used in financing activities		**(1,637)**	(550)	**(1,536)**	(5,343)
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets		**—**	95	**(73)**	(266)
Net expenditures on property, plant and equipment		**(972)**	(1,183)	**(3,535)**	(4,175)
Acquisition of Devon assets	5	**—**	—	**(3,412)**	—
Investment in other long-term assets		**—**	—	**—**	(28)
Net change in non-cash working capital		**118**	46	**(235)**	(345)
Cash flows used in investing activities		**(854)**	(1,042)	**(7,255)**	(4,814)
(Decrease) increase in cash and cash equivalents		**(37)**	(195)	**38**	(36)
Cash and cash equivalents – beginning of period		**176**	296	**101**	137
Cash and cash equivalents – end of period		**$ 139**	$ 101	**$ 139**	$ 101
Interest paid on long-term debt, net		**$ 191**	$ 204	**$ 865**	$ 911
Income taxes paid (received)		**$ 73**	$ (30)	**$ 445**	$ (225)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

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

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

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

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

These interim consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), applicable to the preparation of interim financial statements, including International Accounting Standard ("IAS") 34 "Interim Financial Reporting", following the same accounting policies as the audited consolidated financial statements of the Company as at December 31, 2018, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2018.

2. CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

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

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

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

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

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

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

Further details of the Company's lease assets and lease liabilities on transition to the new Leases standard at January 1, 2019 and as at December 31, 2019 are shown in note 6.

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

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

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

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

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

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

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

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

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

Changes in other accounting policies

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

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

3. 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 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 prospectively adopted the amendments on January 1, 2020.

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 prospectively adopted the amendments on January 1, 2020.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2018	$ 2,348	$ —	$ 37	$ 252	$ 2,637
Additions	**38**	**—**	**33**	**—**	**71**
Acquisition of Devon assets (note 5)	**91**	**—**	**—**	**—**	**91**
Transfers to property, plant and equipment	**(219)**	**—**	**—**	**—**	**(219)**
Foreign exchange adjustments	**—**	**—**	**(1)**	**—**	**(1)**
At December 31, 2019	**$ 2,258**	**$ —**	**$ 69**	**$ 252**	**$ 2,579**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2018	$ 67,007	$ 7,321	$ 5,471	$ 43,147	$ 441	$ 435	$ 123,822
Additions	**2,613**	**349**	**233**	**2,154**	**10**	**34**	**5,393**
Acquisition of Devon assets	**3,325**	**—**	**—**	**—**	**—**	**—**	**3,325**
Transfers from E&E assets	**219**	**—**	**—**	**—**	**—**	**—**	**219**
Disposals/derecognitions [(1)]	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**—**	**(374)**	**(256)**	**—**	**—**	**—**	**(630)**
At December 31, 2019	**$ 72,627**	**$ 7,296**	**$ 3,933**	**$ 45,016**	**$ 451**	**$ 466**	**$ 129,789**
Accumulated depletion and depreciation							
At December 31, 2018	$ 43,881	$ 5,735	$ 4,203	$ 4,981	$ 138	$ 325	$ 59,263
Expense	**3,215**	**256**	**214**	**1,564**	**15**	**23**	**5,287**
Disposals/derecognitions [(1)]	**(537)**	**—**	**(1,515)**	**(285)**	**—**	**(3)**	**(2,340)**
Foreign exchange adjustments and other	**18**	**(279)**	**(190)**	**(13)**	**—**	**—**	**(464)**
At December 31, 2019	**$ 46,577**	**$ 5,712**	**$ 2,712**	**$ 6,247**	**$ 153**	**$ 345**	**$ 61,746**
Net book value							
- at December 31, 2019	**$ 26,050**	**$ 1,584**	**$ 1,221**	**$ 38,769**	**$ 298**	**$ 121**	**$ 68,043**
- at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

(1) Following demobilization of the FPSO at the Olowi field, Gabon in the first quarter of 2019, the Company derecognized property, plant and equipment and associated accumulated depletion and depreciation of $1,515 million.

During the year ended December 31, 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment, excluding the impact of the acquisition disclosed below, for net cash consideration of $80 million and assumed associated asset retirement obligations of $20 million. No net deferred income tax liabilities or pre-tax gains were recognized on these net transactions.

As at December 31, 2019, the Company recognized certain project costs, not subject to depletion and depreciation, of $115 million in the Oil Sands Mining and Upgrading segment (2018 – $1,424 million in the North America Exploration and Production segment). As at December 31, 2018, project costs not subject to depletion and depreciation primarily related to the Kirby North project, which was fully commissioned in 2019.

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, 2019, pre-tax interest of $53 million (December 31, 2018 – $69 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.0% (December 31, 2018 – 3.9%).

Acquisition of Thermal In Situ and Primary Heavy Crude Oil Assets

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

In connection with the acquisition, the Company arranged a new $3,250 million committed term facility (note 9) and assumed certain product transportation commitments (note 17).

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

The following provides a summary of the net assets acquired relating to the acquisition:

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

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

As a result of the acquisition, revenue increased by approximately $1,540 million to $22,871 million and revenue, less production and transportation, blending and feedstock expenses increased by approximately $590 million to $11,895 million for the year ended December 31, 2019.

If the acquisition had been completed on January 1, 2019, the Company estimates that pro forma revenue, net of blending costs would have increased by an additional $1,010 million and pro forma revenue, net of blending costs, less production and transportation and feedstock expenses would have increased by an additional $670 million for the year ended December 31, 2019. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2019, or of future results. Pro forma results are based on available historical information for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

6. LEASES

Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At January 1, 2019 (1)	$ 823	$ 332	$ 252	$ 132	$ 1,539
Additions	**452**	**43**	**12**	**20**	**527**
Depreciation	**(106)**	**(54)**	**(72)**	**(27)**	**(259)**
Derecognitions	**—**	**(6)**	**—**	**—**	**(6)**
Foreign exchange adjustments and other	**(3)**	**2**	**(10)**	**(1)**	**(12)**
At December 31, 2019	**$ 1,166**	**$ 317**	**$ 182**	**$ 124**	**$ 1,789**

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

Lease assets, by Segment

	Dec 31 2019
Exploration and Production	
North America	**$ 300**
North Sea	**38**
Offshore Africa	**154**
Oil Sands Mining and Upgrading	**1,191**
Head office	**106**
	$ 1,789

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at December 31, 2019 were as follows:

	Dec 31 2019
Lease liabilities	**$ 1,809**
Less: current portion	**233**
	$ 1,576

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

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

	Three Months Ended Dec 31 2019	Year Ended Dec 31 2019
Expenses relating to short-term leases (1)	**$ 112**	**$ 448**
Interest expense on lease liabilities	**$ 18**	**$ 70**
Variable lease payments not included in the measurement of lease liabilities	**$ 29**	**$ 118**
Total cash outflows for leases (2)	**$ 299**	**$ 1,178**

(1) In addition, during the three months ended December 31, 2019, the Company capitalized $76 million (year ended December 31, 2019 - $305 million) of short-term leases as additions to property, plant and equipment.

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

Impacts to the consolidated financial statements on transition

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

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

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

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

(2) Commitments for operating leases, previously reported in note 17, are now reported as part of lease liabilities and included in other long-term liabilities in note 10. Operating leases previously reported in note 17 have been aggregated into one line in the reconciliation table. Other non-lease commitments continue to be reported in the table in note 17.

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

7. INVESTMENTS

As at December 31, 2019, the Company had the following investments:

		Dec 31 2019		Dec 31 2018
Investment in PrairieSky Royalty Ltd.	**$**	**345**	$	400
Investment in Inter Pipeline Ltd.		**145**		124
	$	**490**	$	524

Investment in PrairieSky Royalty Ltd.

The Company's investment of 22.6 million common shares of PrairieSky Royalty Ltd. ("PrairieSky") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, the Company's investment in PrairieSky was classified as a current asset.

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

	Three Months Ended				Year Ended			
		Dec 31 2019		Dec 31 2018		**Dec 31 2019**		Dec 31 2018
Fair value loss from PrairieSky	**$**	**73**	$	114	**$**	**55**	$	326
Dividend income from PrairieSky		**(4)**		(4)		**(17)**		(17)
	$	**69**	$	110	**$**	**38**	$	309

Investment in Inter Pipeline Ltd.

The Company's investment of 6.4 million common shares of Inter Pipeline Ltd. ("Inter Pipeline") does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at December 31, 2019, 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 2019		Dec 31 2018		**Dec 31 2019**		Dec 31 2018
Fair value loss (gain) from Inter Pipeline	**$**	**4**	$	20	**$**	**(21)**	$	43
Dividend income from Inter Pipeline		**(3)**		(3)		**(11)**		(11)
	$	**1**	$	17	**$**	**(32)**	$	32

8. OTHER LONG-TERM ASSETS

	Dec 31 2019	Dec 31 2018
North West Redwater Partnership subordinated debt [1]	**$ 652**	$ 591
Prepaid cost of service toll	**130**	62
Investment in North West Redwater Partnership	**—**	287
Risk management (note 16)	**290**	373
Long-term inventory	**121**	96
Other	**84**	50
	1,277	1,459
Less: current portion	**54**	116
	$ 1,223	$ 1,343

(1) Includes accrued interest.

Investment in North West Redwater Partnership

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

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In the first quarter of 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In December 2019, the light oil refinery completed activities relating to the planned maintenance shutdown. The Project continues to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. As at December 31, 2019, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at December 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $213 million, for a Company total of $652 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 17). The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at December 31, 2019, the Company had recognized $130 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility, of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis. During 2019, Redwater Partnership extended the $1,500 million non-revolving facility, previously scheduled to mature in February 2020, to February 2021. As at December 31, 2019, Redwater Partnership had borrowings of $2,715 million under the syndicated credit facility.

During the three months ended December 31, 2019, the Company recognized an equity loss from Redwater Partnership of $73 million (three months ended December 31, 2018 – gain of $nil; year ended December 31, 2019 – loss of $287 million; year ended December 31, 2018 – loss of $5 million), reducing the carrying value in Redwater Partnership to $nil. The unrecognized share of losses to date from Redwater Partnership for the three months and year ended December 31, 2019 was $59 million.

9. LONG-TERM DEBT

		Dec 31 2019		Dec 31 2018
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**1,688**	$	831
Medium-term notes		**4,300**		5,300
		5,988		6,131
US dollar denominated debt, unsecured				
Bank credit facilities (December 31, 2019 – US$3,745 million; December 31, 2018 – US$2,954 million)		**4,855**		4,031
Commercial paper (December 31, 2019 – US$254 million; December 31, 2018 – US$104 million)		**329**		141
US dollar debt securities (December 31, 2019 – US$7,650 million; December 31, 2018 – US$7,650 million)		**9,918**		10,439
		15,102		14,611
Long-term debt before transaction costs and original issue discounts, net		**21,090**		20,742
Less: original issue discounts, net (1)		**17**		17
transaction costs (1) (2)		**91**		102
		20,982		20,623
Less: current portion of commercial paper		**329**		141
current portion of other long-term debt (1) (2)		**2,062**		1,000
	$	**18,591**	$	19,482

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

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

Bank Credit Facilities and Commercial Paper

As at December 31, 2019, the Company had in place revolving bank credit facilities of $4,959 million, of which $4,737 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 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 $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company's North Sea operations.

During the fourth quarter of 2019, the Company fully repaid and cancelled the $1,000 million non-revolving term credit facility scheduled to mature in May 2020. Previously, in the third quarter of 2019, the Company repaid and cancelled $800 million of this non-revolving term credit facility.

During the fourth quarter of 2019, the $2,200 million non-revolving term credit facility, originally due October 2020, was extended to February 2023 and increased to $2,650 million.

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

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate. As at December 31, 2019, the non-revolving term credit facilities were fully drawn.

During the fourth quarter of 2019, the Company extended the $2,425 million revolving syndicated credit facility scheduled to mature in June 2021 to June 2023. Previously, in the second quarter of 2019, the Company extended $330 million of this revolving syndicated credit facility originally due June 2019 to June 2021.

The revolving credit facilities are extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.

Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.

During the fourth quarter of 2019, the Company reduced the £15 million demand credit facility related to the Company's North Sea operations, to £5 million.

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2019 was 2.5% (December 31, 2018 – 2.6%), and on total long-term debt outstanding for the year ended December 31, 2019 was 4.0% (December 31, 2018 – 3.9%).

As at December 31, 2019, letters of credit and guarantees aggregating to $468 million were outstanding.

Medium-Term Notes

During the fourth quarter of 2019, the Company repaid $500 million of 2.60% medium-term notes. During the second quarter of 2019, the Company repaid $500 million of 3.05% medium-term notes.

In July 2019, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada, which expires in August 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

In July 2019, the Company filed a new base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2021, replacing the Company's previous base shelf prospectus, which would have expired in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

10. OTHER LONG-TERM LIABILITIES

	Dec 31 2019	Dec 31 2018
Asset retirement obligations	**$ 5,771**	$ 3,886
Lease liabilities (note 6)	**1,809**	—
Share-based compensation	**297**	124
Risk management (note 16)	**112**	17
Deferred purchase consideration (1)	**95**	118
Other	**98**	80
	8,182	4,225
Less: current portion	**819**	335
	$ 7,363	$ 3,890

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

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 3.8% (December 31, 2018 – 5.0%) and inflation rates of up to 2% (December 31, 2018 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2019	Dec 31 2018
Balance – beginning of year	$ 3,886	$ 4,327
Liabilities incurred	15	19
Liabilities acquired, net	198	6
Liabilities settled	(296)	(290)
Asset retirement obligation accretion	190	186
Revision of cost, inflation rates and timing estimates	412	(111)
Change in discount rates	1,412	(334)
Foreign exchange adjustments	(46)	83
Balance – end of year	5,771	3,886
Less: current portion	208	186
	$ 5,563	$ 3,700

Share-Based Compensation

The liability for share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's Stock Option Plan provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recognizes a liability for potential cash settlements under these plans. 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 and PSUs are settled in cash.

	Dec 31 2019	Dec 31 2018
Balance – beginning of year	$ 124	$ 414
Share-based compensation expense (recovery)	223	(146)
Cash payment for stock options surrendered	(2)	(5)
Transferred to common shares	(53)	(120)
Charged to (recovered from) Oil Sands Mining and Upgrading, net	5	(19)
Balance – end of year	297	124
Less: current portion	227	92
	$ 70	$ 32

Included within share-based compensation liability as at December 31, 2019 was $62 million related to PSUs granted to certain executive employees (December 31, 2018 – $13 million).

11. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Year Ended	
Expense (recovery)	**Dec 31 2019**	Dec 31 2018	**Dec 31 2019**	Dec 31 2018
Current corporate income tax – North America	**$ (20)**	$ (254)	**$ 354**	$ 312
Current corporate income tax – North Sea	**40**	8	**112**	28
Current corporate income tax – Offshore Africa	**7**	11	**44**	54
Current PRT [(1)] – North Sea	**—**	—	**(89)**	(29)
Other taxes	**4**	1	**13**	9
Current income tax	**31**	(234)	**434**	374
Deferred corporate income tax	**194**	112	**(895)**	540
Deferred PRT [(1)] – North Sea	**—**	(1)	**1**	17
Deferred income tax	**194**	111	**(894)**	557
Income tax	**$ 225**	$ (123)	**$ (460)**	$ 931

(1) Petroleum Revenue Tax

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

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Year Ended Dec 31, 2019		
Issued common shares	**Number of shares** (thousands)		**Amount**
Balance – beginning of year	**1,201,886**	**$**	**9,323**
Issued upon exercise of stock options	**10,871**		**360**
Previously recognized liability on stock options exercised for common shares	**—**		**53**
Purchase of common shares under Normal Course Issuer Bid	**(25,900)**		**(203)**
Balance – end of year	**1,186,857**	**$**	**9,533**

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 4, 2020, the Board of Directors declared a quarterly dividend of $0.425 per common share, an increase from the previous quarterly dividend of $0.375 per common share. The dividend is payable on April 1, 2020.

Normal Course Issuer Bid

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

For the year ended December 31, 2019, the Company purchased 25,900,000 common shares at a weighted average price of $36.32 per common share for a total cost of $941 million. Retained earnings were reduced by $738 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2019, the Company purchased 6,600,000 common shares at a weighted average price of $39.41 per common share for a total cost of $260 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at December 31, 2019:

	Year Ended Dec 31, 2019		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of year	**46,685**	**$**	**37.92**
Granted	**16,314**	**$**	**34.84**
Surrendered for cash settlement	**(1,003)**	**$**	**34.52**
Exercised for common shares	**(10,871)**	**$**	**33.16**
Forfeited	**(3,479)**	**$**	**37.65**
Outstanding – end of year	**47,646**	**$**	**38.04**
Exercisable – end of year	**17,057**	**$**	**38.74**

The Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2019	Dec 31 2018
Derivative financial instruments designated as cash flow hedges	**$ 71**	$ 13
Foreign currency translation adjustment	**(37)**	109
	$ 34	$ 122

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, 2019, the ratio was within the target range at 37.3%.

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 2019	Dec 31 2018
Long-term debt, net (1)	**$ 20,843**	$ 20,522
Total shareholders' equity	**$ 34,991**	$ 31,974
Debt to book capitalization	**37.3%**	39.1%

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

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. At December 31, 2019, the Company was in compliance with this covenant.

15. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Year Ended	
	Dec 31 2019	Dec 31 2018	Dec 31 2019	Dec 31 2018
Weighted average common shares outstanding – basic (thousands of shares)	**1,184,428**	1,204,998	**1,190,977**	1,218,798
Effect of dilutive stock options (thousands of shares)	**2,188**	—	**2,129**	4,960
Weighted average common shares outstanding – diluted (thousands of shares)	**1,186,616**	1,204,998	**1,193,106**	1,223,758
Net earnings (loss)	**$ 597**	$ (776)	**$ 5,416**	$ 2,591
Net earnings (loss) per common share – basic	**$ 0.50**	$ (0.64)	**$ 4.55**	$ 2.13
– diluted	**$ 0.50**	$ (0.64)	**$ 4.54**	$ 2.12

16. FINANCIAL INSTRUMENTS

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

	Dec 31, 2019				
Asset (liability)	**Financial assets at amortized cost**	**Fair value through profit or loss**	**Derivatives used for hedging**	**Financial liabilities at amortized cost**	**Total**
Accounts receivable	**$ 2,465**	**$ —**	**$ —**	**$ —**	**$ 2,465**
Investments	**—**	**490**	**—**	**—**	**490**
Other long-term assets	**652**	**—**	**290**	**—**	**942**
Accounts payable	**—**	**—**	**—**	**(816)**	**(816)**
Accrued liabilities	**—**	**—**	**—**	**(2,611)**	**(2,611)**
Other long-term liabilities (1)	**—**	**(21)**	**(91)**	**(1,904)**	**(2,016)**
Long-term debt (2)	**—**	**—**	**—**	**(20,982)**	**(20,982)**
	$ 3,117	**$ 469**	**$ 199**	**$ (26,313)**	**$ (22,528)**

	Dec 31, 2018				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 1,148	$ —	$ —	$ —	$ 1,148
Investments	—	524	—	—	524
Other long-term assets	591	12	361	—	964
Accounts payable	—	—	—	(779)	(779)
Accrued liabilities	—	—	—	(2,356)	(2,356)
Other long-term liabilities (1)	—	(17)	—	(118)	(135)
Long-term debt (2)	—	—	—	(20,623)	(20,623)
	$ 1,739	$ 519	$ 361	$ (23,876)	$ (21,257)

(1) Includes $1,809 million of lease liabilities (December 31, 2018 – $nil) and $95 million of deferred purchase consideration payable over the next four years (December 31, 2018 – $118 million).

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

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

	Dec 31, 2019			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3 (4) (5)**
Investments (3)	**$ 490**	**$ 490**	**$ —**	**$ —**
Other long-term assets	**$ 942**	**$ —**	**$ 290**	**$ 652**
Other long-term liabilities	**$ (207)**	**$ —**	**$ (112)**	**$ (95)**
Fixed rate long-term debt (6) (7)	**$ (14,110)**	**$ (15,938)**	**$ —**	**$ —**

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

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

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

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

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

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

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

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

Risk Management

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

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

Asset (liability)	**Dec 31 2019**	Dec 31 2018
Derivatives held for trading		
Foreign currency forward contracts	**$ (10)**	$ 8
Natural gas AECO basis swaps	**(8)**	1
Natural gas AECO fixed price swaps	**(3)**	3
Crude oil WCS [1] differential swaps	**—**	(17)
Cash flow hedges		
Foreign currency forward contracts	**(91)**	70
Cross currency swaps	**290**	291
	$ 178	$ 356
Included within:		
Current portion of other long-term assets	**$ 8**	$ 92
Current portion of other long-term liabilities	**(112)**	(17)
Other long-term assets	**282**	281
	$ 178	$ 356

(1) Western Canadian Select

For the year ended December 31, 2019, the Company recognized a gain of $3 million (year ended December 31, 2018 – gain of $2 million) related to ineffectiveness arising from cash flow hedges.

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

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

Asset (liability)	Dec 31 2019	Dec 31 2018
Balance – beginning of year	$ 356	$ 101
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	(13)	35
Foreign exchange	(231)	260
Other comprehensive income (loss)	66	(40)
Balance – end of year	178	356
Less: current portion	(104)	75
	$ 282	$ 281

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

	Three Months Ended		Year Ended	
	Dec 31 2019	Dec 31 2018	Dec 31 2019	Dec 31 2018
Net realized risk management loss (gain)	$ 11	$ (45)	$ 64	$ (99)
Net unrealized risk management loss (gain)	17	27	13	(35)
	$ 28	$ (18)	$ 77	$ (134)

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

	Remaining term	Volume	Weighted average price	Index
Natural Gas				
AECO basis swaps	Jan 2020 – Mar 2020	140,000 MMbtu/d	US$0.93	NYMEX
AECO fixed price swaps	Apr 2020 – Oct 2020	102,500 GJ/d	$1.51	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At December 31, 2019, the Company had no interest rate swap contracts outstanding.

Foreign currency exchange rate risk management

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

At December 31, 2019, the Company had the following cross currency swap contracts outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swaps	Jan 2020	–	Nov 2021	US$500	1.022	3.45%	3.96%
	Jan 2020	–	Mar 2038	US$550	1.170	6.25%	5.76%

All cross currency swap derivative financial instruments were designated as hedges at December 31, 2019 and were classified as cash flow hedges.

In addition to the cross currency swap contracts noted above, at December 31, 2019, the Company had US$4,564 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,999 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, 2019, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At December 31, 2019, the Company had net risk management assets of $265 million with specific counterparties related to derivative financial instruments (December 31, 2018 – $361 million). The carrying amount of financial assets approximates the maximum credit exposure.

c) Liquidity risk

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

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

The maturity dates of the Company's financial liabilities were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	$ 816	$ —	$ —	$ —
Accrued liabilities	$ 2,611	$ —	$ —	$ —
Long-term debt (1)	$ 2,391	$ 1,552	$ 8,921	$ 8,226
Other long-term liabilities (2)	$ 370	$ 196	$ 436	$ 1,014
Interest and other financing expense (3)	$ 881	$ 813	$ 1,771	$ 4,856

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

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, $233 million; one to less than two years, $171 million; two to less than five years, $391 million; and thereafter $1,014 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at December 31, 2019.

17. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2019 [(1)]:

		2020		2021		2022		2023		2024		Thereafter
Product transportation [(2) (3)]	$	730	$	722	$	637	$	726	$	699	$	7,907
North West Redwater Partnership service toll [(4)]	$	133	$	167	$	157	$	164	$	156	$	2,815
Offshore vessels and equipment	$	69	$	63	$	9	$	—	$	—	$	—
Field equipment and power	$	27	$	21	$	20	$	21	$	20	$	249
Other	$	26	$	20	$	17	$	17	$	17	$	30

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

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

(3) Includes commitments pertaining to a 20 year product transportation agreement on the Trans Mountain Pipeline Expansion. In addition, the Company has entered into certain product transportation agreements on pipelines that have not yet received regulatory and other approvals. The Company may be required to reimburse certain construction costs to the service provider under certain conditions.

(4) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,260 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	
	2019	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs	**2,882**	923	**9,679**	7,254	**297**	218	**860**	753	**94**	204	**632**	628	**3,273**	1,345	**11,171**	8,635
Natural gas	**327**	422	**1,150**	1,256	**12**	28	**57**	140	**15**	17	**67**	70	**354**	467	**1,274**	1,466
Other [1]	**—**	—	**6**	—	**2**	—	**5**	—	**2**	—	**8**	—	**4**	—	**19**	—
Total segmented product sales	**3,209**	1,345	**10,835**	8,510	**311**	246	**922**	893	**111**	221	**707**	698	**3,631**	1,812	**12,464**	10,101
Less: royalties	**(308)**	(38)	**(998)**	(723)	**(1)**	(1)	**(2)**	(2)	**(7)**	(9)	**(42)**	(51)	**(316)**	(48)	**(1,042)**	(776)
Segmented revenue	**2,901**	1,307	**9,837**	7,787	**310**	245	**920**	891	**104**	212	**665**	647	**3,315**	1,764	**11,422**	9,325
Segmented expenses																
Production	**628**	589	**2,425**	2,405	**121**	134	**391**	405	**30**	87	**109**	208	**779**	810	**2,925**	3,018
Transportation, blending and feedstock	**1,042**	541	**2,935**	2,587	**4**	4	**19**	22	**1**	1	**2**	2	**1,047**	546	**2,956**	2,611
Depletion, depreciation and amortization	**935**	779	**3,326**	3,132	**98**	88	**308**	257	**50**	62	**242**	201	**1,083**	929	**3,876**	3,590
Asset retirement obligation accretion	**27**	21	**95**	87	**7**	8	**28**	29	**2**	2	**6**	9	**36**	31	**129**	125
Risk management activities (commodity derivatives)	**13**	9	**49**	(10)	**—**	—	**—**	—	**—**	—	**—**	—	**13**	9	**49**	(10)
Gain on acquisition, disposition and revaluation of properties	**—**	(5)	**—**	(277)	**—**	—	**—**	(139)	**—**	(36)	**—**	(36)	**—**	(41)	**—**	(452)
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,645**	1,934	**8,830**	7,924	**230**	234	**746**	574	**83**	116	**359**	384	**2,958**	2,284	**9,935**	8,882
Segmented earnings (loss) before the following	**256**	(627)	**1,007**	(137)	**80**	11	**174**	317	**21**	96	**306**	263	**357**	(520)	**1,487**	443
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
Loss from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax expense (recovery)																
Deferred income tax expense (recovery)																
Net earnings (loss)																

	Oil Sands Mining and Upgrading				Midstream and Refining				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	
(millions of Canadian dollars, unaudited)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales																
Crude oil and NGLs [2]	**2,633**	1,838	**11,340**	11,521	**26**	24	**88**	102	**15**	120	**351**	410	**5,947**	3,327	**22,950**	20,668
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**28**	37	**145**	148	**382**	504	**1,419**	1,614
Other [1]	**2**	—	**6**	—	**—**	—	**—**	—	**—**	—	**—**	—	**6**	—	**25**	—
Total segmented product sales	**2,635**	1,838	**11,346**	11,521	**26**	24	**88**	102	**43**	157	**496**	558	**6,335**	3,831	**24,394**	22,282
Less: royalties	**(118)**	(81)	**(481)**	(479)	**—**	—	**—**	—	**—**	—	**—**	—	**(434)**	(129)	**(1,523)**	(1,255)
Segmented revenue	**2,517**	1,757	**10,865**	11,042	**26**	24	**88**	102	**43**	157	**496**	558	**5,901**	3,702	**22,871**	21,027
Segmented expenses																
Production	**856**	797	**3,276**	3,367	**5**	5	**20**	21	**8**	15	**56**	58	**1,648**	1,627	**6,277**	6,464
Transportation, blending and feedstock [2]	**330**	174	**1,306**	1,087	**—**	—	**—**	—	**39**	144	**437**	491	**1,416**	864	**4,699**	4,189
Depletion, depreciation and amortization	**464**	396	**1,656**	1,557	**3**	3	**14**	14	**—**	—	**—**	—	**1,550**	1,328	**5,546**	5,161
Asset retirement obligation accretion	**14**	15	**61**	61	**—**	—	**—**	—	**—**	—	**—**	—	**50**	46	**190**	186
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**13**	9	**49**	(10)
Gain on acquisition, disposition and revaluation of properties	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	(41)	**—**	(452)
Equity loss from investments	**—**	—	**—**	—	**73**	—	**287**	5	**—**	—	**—**	—	**73**	—	**287**	5
Total segmented expenses	**1,664**	1,382	**6,299**	6,072	**81**	8	**321**	40	**47**	159	**493**	549	**4,750**	3,833	**17,048**	15,543
Segmented earnings (loss) before the following	**853**	375	**4,566**	4,970	**(55)**	16	**(233)**	62	**(4)**	(2)	**3**	9	**1,151**	(131)	**5,823**	5,484
Non–segmented expenses																
Administration													**95**	91	**344**	325
Share-based compensation													**161**	(148)	**223**	(146)
Interest and other financing expense													**217**	179	**836**	739
Risk management activities (other)													**15**	(27)	**28**	(124)
Foreign exchange (gain) loss													**(229)**	546	**(570)**	827
Loss from investments													**70**	127	**6**	341
Total non–segmented expenses													**329**	768	**867**	1,962
Earnings (loss) before taxes													**822**	(899)	**4,956**	3,522
Current income tax expense (recovery)													**31**	(234)	**434**	374
Deferred income tax expense (recovery)													**194**	111	**(894)**	557
Net earnings (loss)													**597**	(776)	**5,416**	2,591

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

Capital Expenditures [1]

	Year Ended					
	Dec 31, 2019			Dec 31, 2018		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 129**	**$ (219)**	**$ (90)**	$ 118	$ (52)	$ 66
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa [4]	**35**	**(2)**	**33**	(54)	—	(54)
Oil Sands Mining and Upgrading [5]	**—**	**—**	**—**	218	(225)	(7)
	$ 164	**$ (221)**	**$ (57)**	$ 282	$ (277)	$ 5
Property, plant and equipment						
Exploration and Production						
North America [3]	**$ 4,702**	**$ 918**	**$ 5,620**	$ 2,553	$ (362)	$ 2,191
North Sea	**196**	**153**	**349**	131	(597)	(466)
Offshore Africa [6]	**194**	**(1,476)**	**(1,282)**	228	(86)	142
	5,092	**(405)**	**4,687**	2,912	(1,045)	1,867
Oil Sands Mining and Upgrading [7]	**1,525**	**344**	**1,869**	1,229	(166)	1,063
Midstream and Refining	**10**	**—**	**10**	13	—	13
Head office	**34**	**(3)**	**31**	21	—	21
	$ 6,661	**$ (64)**	**$ 6,597**	$ 4,175	$ (1,211)	$ 2,964

(1) This table provides a reconciliation of capitalized costs, reported in note 4 and note 5, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

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

(4) Excludes the impact of a pre-tax cash gain of $16 million on the disposition of certain exploration and evaluation assets in the fourth quarter of 2018.

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

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

(7) Net expenditures include capitalized interest and share-based compensation.

Segmented Assets

		Dec 31 2019		Dec 31 2018
Exploration and Production				
North America	**$**	**30,963**	$	27,199
North Sea		**1,948**		1,699
Offshore Africa		**1,529**		1,471
Other		**30**		33
Oil Sands Mining and Upgrading		**42,006**		39,634
Midstream and Refining		**1,418**		1,413
Head office		**227**		110
	$	**78,121**	$	71,559

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 2019. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended December 31, 2019:	
Interest coverage (times)	
Net earnings (1)	6.5x
Adjusted funds flow (2)	13.0x

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

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

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Corporate Information

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Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ
New York Stock Exchange
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