FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2019 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2019 FIRST QUARTER RESULTS

Commenting on the Company's first quarter 2019 results, Steve Laut, Executive Vice-Chairman of Canadian Natural stated, "In the first quarter, the Company demonstrated the resilience and strength of its long life low decline and low capital exposure assets, generating significant adjusted funds flow of approximately $2.2 billion. The Company was able to achieve adjusted funds flow that exceeded net capital expenditures by approximately $1.3 billion, largely due to a strong operational quarter and improvement in crude oil differentials, driven by the Government of Alberta's mandatory production curtailments which is strongly supported by Canadian Natural.

Canadian Natural's top tier low sustaining capital required to maintain production levels, combined with industry leading effective and efficient operations, were evident in Q1/19 as adjusted funds flow less net capital expenditures was comparable to Q1/18 when West Texas Intermediate ("WTI") was approximately US$8.00/bbl higher."

Canadian Natural's President, Tim McKay, added, "Operations were strong in the first quarter as our large, balanced and diverse asset base allowed the Company to strategically manage through the mandatory production curtailments to maximize value. Production was as expected in Q1/19, reaching approximately 1,035,000 BOE/d, consisting of 54% light crude oil, NGLs and Synthetic Crude Oil ("SCO"), 22% heavy crude oil and 24% natural gas.

Effective and efficient operations across the Company continue to be a significant driver of value creation for Canadian Natural. Our Oil Sands Mining and Upgrading segment Q1/19 operating costs were top tier at $21.46/bbl (US$16.14/bbl) of SCO. Equally as impressive were our Conventional E&P assets achieving operating costs of $12.68/BOE (US$9.54/BOE) in Q1/19, a reduction of 6% from Q4/18 levels, strong results given mandatory production curtailments in the quarter."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, continued, "In the first quarter, Canadian Natural realized solid results as profitability and value from our diverse asset base generated net earnings of approximately $1.0 billion. Net earnings were up dramatically from Q4/18, reflecting the dysfunctional crude oil market which existed in Q4/18 and the success of the Government of Alberta's mandatory production curtailment program to restore a normal market in Q1/19.

The Company's capital discipline and financial strength resulted in robust free cash flow of $860 million, after net capital expenditures and dividends. Share purchases were $241 million (6.65 million shares) in Q1/19 pursuant to the Company's free cash flow allocation policy. As a result of the increased confidence in free cash flow levels for the remainder of 2019, the rate of share purchases has increased as Q2/19 commenced, with purchases totaling $159 million (4.05 million shares) from April 1, 2019 to May 8th, 2019."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Net earnings (loss)	**$ 961**	$ (776)	$ 583
Per common share – basic	**$ 0.80**	$ (0.64)	$ 0.48
– diluted	**$ 0.80**	$ (0.64)	$ 0.47
Adjusted net earnings (loss) from operations (1)	**$ 838**	$ (255)	$ 885
Per common share – basic	**$ 0.70**	$ (0.21)	$ 0.72
– diluted	**$ 0.70**	$ (0.21)	$ 0.71
Cash flows from operating activities	**$ 996**	$ 1,397	$ 2,469
Adjusted funds flow (2)	**$ 2,240**	$ 1,229	$ 2,323
Per common share – basic	**$ 1.87**	$ 1.02	$ 1.90
– diluted	**$ 1.86**	$ 1.02	$ 1.89
Cash flows used in investing activities	**$ 1,029**	$ 1,042	$ 1,369
Net capital expenditures (3)	**$ 977**	$ 1,181	$ 1,103
Daily production, before royalties			
Natural gas (MMcf/d)	**1,510**	1,488	1,614
Crude oil and NGLs (bbl/d)	**783,512**	833,358	854,558
Equivalent production (BOE/d) (4)	**1,035,212**	1,081,368	1,123,546

(1) Adjusted net earnings (loss) from operations is a non-GAAP measure that the Company utilizes to evaluate its performance, as it demonstrates the Company's ability to generate after-tax operating earnings from its core business areas. The derivation of this measure is discussed in the Management's Discussion and Analysis ("MD&A").

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

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

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

- Net earnings of $961 million were realized in Q1/19, increases of $1,737 million and $378 million over Q4/18 and Q1/18 levels, respectively. Adjusted net earnings of $838 million were achieved in Q1/19, a $1,093 million increase over Q4/18 levels.
- Cash flows from operating activities were $996 million in Q1/19, a decrease of $401 million compared to Q4/18 levels.
- Canadian Natural generated significant quarterly adjusted funds flow of $2,240 million in Q1/19, an increase of 82% or $1,011 million over Q4/18 levels. The increase quarter over quarter was primarily due to strong operations in the quarter and higher netbacks in all segments, as crude oil markets in Canada returned to normal with the Government of Alberta's mandatory production curtailments.
- Cash flows used in investing activities remain disciplined at $1,029 million in Q1/19, in-line with Q4/18 levels.
- Canadian Natural delivered strong quarterly free cash flow of $860 million after net capital expenditures of $977 million and dividend requirements of $403 million, reflecting the strength of our long life low decline asset base and our effective and efficient operations.

- Canadian Natural is committed to returns to shareholders, returning a total of $644 million in the quarter, $403 million by way of dividends and $241 million by way of share purchases.
  - Share purchases for cancellation in the quarter totaled 6,650,000 common shares at a weighted average share price of $36.24. Subsequent to quarter end and up to and including May 8, 2019, the Company executed on additional share purchases of 4,050,000 common shares for cancellation at a weighted average share price of $39.34.
  - In Q1/19 the Company increased its quarterly dividend by 12% from Q4/18 levels, marking the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's sustainability and robustness of the Company's asset base and its ability to generate significant adjusted funds flow.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on July 1, 2019.
  - The Company's Board of Director's has approved a motion to renew the Normal Course Issuance Bid ("NCIB") and the continuation of the free cash flow allocation policy.
- The Company achieved quarterly production volumes of 1,035,212 BOE/d in Q1/19, a decrease of 4% from Q4/18 levels reflecting the Government of Alberta's mandatory production curtailments.
  - The Company continues to strategically adjust timing of planned maintenance activities across its asset base, including Oil Sands Mining and Upgrading, thermal in situ and North American Exploration & Production ("E&P") to maximize value within the current curtailment environment.
- At the Company's world class Oil Sands Mining and Upgrading assets, industry leading operations provided quarterly production of 416,206 bbl/d of Synthetic Crude Oil ("SCO"), a decrease of 7% from Q4/18 levels. The decrease in production was primarily due to mandatory curtailments, previously announced accelerated maintenance activities as well as unplanned maintenance.
  - Operating costs were top tier, as the Company realized quarterly unadjusted operating costs of $21.46/bbl (US$16.14/bbl) of SCO in Q1/19, in-line with Q1/18 levels, strong results given curtailment and maintenance activities in the quarter.
  - As previously announced on May 1, 2019, Canadian Natural provided a follow up on a fire which occurred at the Scotford Upgrader on April 15, 2019, in which the Company has a 70% interest. The fire was promptly extinguished, all personnel were accounted for, and there were no reported injuries.
    - The fire was contained to a process furnace in the North Upgrader, while operations at the base upgrader plant ("South Upgrader") were not impacted by the fire. The planned 38 day turnaround began on April 14, 2019 at the Scotford Upgrader, during which time the South Upgrader will run at a restricted net processing rate of approximately 140,000 bbl/d of SCO. Upon completion of the planned maintenance, May and June average net production at the Albian mines is targeted to be approximately 171,500 bbl/d versus the Company's previously targeted net curtailment production volumes at the Albian mines of approximately 178,500 bbl/d. The cost for repairs of the North Upgrader is estimated to be approximately $15 million gross and is targeted to be fully operational by early June. The Company continues to optimize other assets in Alberta to mitigate the impacts of curtailments on its production.
- International E&P quarterly production volumes were strong in Q1/19, averaging 47,869 bbl/d, increases of 11% and 17% from Q4/18 and Q1/18 levels respectively. The increases were mainly as a result of successful 2018 drilling and turnaround activities that were completed in Q4/18 in the North Sea. Additionally, in Offshore Africa, successful 2018 drilling contributed to International production increases from Q1/18, partially offset by natural declines.
  - International production volumes benefit from premium Brent pricing, generating significant adjusted funds flow for the Company.
- In the Company's thermal in situ operations, pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.
- As previously announced, at the Company's Kirby North Steam Assisted Gravity Drainage ("SAGD") project, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule with overall cost performance remaining on budget. The commissioning of the central processing facility

was also top tier and as a result, the project began steaming on May 1, 2019 and targets to progressively ramp up production towards Kirby North's overall capacity of 40,000 bbl/d, in late 2020.

- Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At March 31, 2019 the Company had approximately $4,230 million of available liquidity, including cash and cash equivalents.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

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

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

	Three Months Ended Mar 31			
	2019		2018	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**30**	**30**	127	122
Natural gas	**10**	**8**	8	5
Dry	**1**	**1**	2	2
Subtotal	**41**	**39**	137	129
Stratigraphic test / service wells	**375**	**332**	528	450
Total	**416**	**371**	665	579
Success rate (excluding stratigraphic test / service wells)		**97%**		98%

- The Company's total crude oil and natural gas drilling program of 39 net wells for the three months ended March 31, 2019, excluding strat/service wells, decreased by 90 net wells from the same period in 2018. The Company's drilling levels reflect the disciplined capital allocation process and continued actions to improve execution.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs production (bbl/d)	**225,291**	240,942	245,609
Net wells targeting crude oil	**28**	62	101
Net successful wells drilled	**28**	61	99
Success rate	**100%**	98%	98%

- North America crude oil and NGLs averaged 225,291 bbl/d in Q1/19, reflecting mandatory production curtailments, representing a decrease of 6% from Q4/18 levels that were already voluntarily curtailed by approximately 10,600 bbl/d.

- Canadian Natural's primary heavy crude oil production averaged 68,473 bbl/d in Q1/19, reflecting mandatory production curtailments, and the strategic decision to reduce activity on drilling, workovers, recompletions and optimization activities in a curtailed market in Q1/19, representing a decrease of 14% from Q4/18 levels that were already voluntarily curtailed by approximately 9,600 bbl/d.
    - Operating costs of $17.30/bbl were achieved in the Company's primary heavy crude oil operations in the quarter, a 2% increase from Q1/18 levels, strong results given lower production volumes due to mandatory production curtailments.
- North America light crude oil and NGL production averaged 95,578 bbl/d in Q1/19, reflecting mandatory production curtailments in the Company's light crude oil segment, representing a decrease of 3% from Q4/18 levels that were already voluntarily curtailed by approximately 1,000 bbl/d.
    - Within the greater Wembley area, results continue to exceed expectations. The Company brought 10 net wells on production in Q1/19 that were drilled late in 2018, with initial 30 day liquids production rates averaging approximately 580 bbl/d per well. An additional 3 net wells are targeted to come on production in Q2/19 and Q3/19. Within the greater Wembley area, the Company has identified 155 net Montney sections and 363 incremental potential premium light crude oil and liquids rich well locations.
    - In the Company's Karr area, 12 net wells came on production in Q1/19, 9 were drilled in Q4/18 and 3 were drilled in Q1/19. Early results have been strong from these wells, with total liquids production of approximately 315 bbl/d per well, exceeding expectations.
    - In Southeast Saskatchewan and Manitoba, the Company drilled 9 net light crude oil wells in Q1/19. Subsequent to quarter end, these wells came on stream and are currently producing approximately 85 bbl/d per well, in-line with expectations. Production from these Saskatchewan and Manitoba wells are not impacted by production curtailments.
    - In Q1/19 operating costs of $15.86/bbl were realized in the Company's North America light crude oil and NGL areas, comparable to Q1/18 levels.
- Pelican Lake quarterly production averaged 61,240 bbl/d in Q1/19, a decrease of 2% from Q4/18 levels.
    - Strong operating costs of $6.69/bbl were achieved in Q1/19 at Pelican Lake, a reduction of 5% from Q1/18 levels.
    - Subsequent to quarter end, in April 2019 facility consolidation was completed on time and on budget, and as a result operating cost savings of approximately $6 million per year are targeted.
    - The Company targets to expand the polymer flood further in Q2/19, with the conversion of 3 additional pads from water flood to polymer flood.

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

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Bitumen production (bbl/d)	**94,146**	102,112	111,851
Net wells targeting bitumen	—	41	22
Net successful wells drilled	—	40	22
Success rate	—	98%	100%

▪ Thermal in situ production volumes averaged 94,146 bbl/d in Q1/19, reflecting mandatory production curtailments, representing a decrease of 8% from Q4/18 levels that were already voluntarily curtailed by approximately 13,900 bbl/d at Primrose.

- At Primrose, Q1/19 production volumes averaged 61,925 bbl/d, a decrease of 9% from Q4/18 levels, as a result of production curtailments. Including energy costs, operating costs were $20.23/bbl in Q1/19, an increase of 22% from Q1/18, reflecting lower volumes due to curtailments and higher energy costs.

- ◦ Pad additions at Primrose continue to be on budget and ahead of schedule with initial production targeted in Q4/19. The program targets to add approximately 26,000 bbl/d in the first 12 months of production. These pad additions are high return activities as the Company utilizes available excess oil processing and steam capacity at Primrose.

- At Kirby South, SAGD production volumes averaged 29,692 bbl/d in Q1/19, a decrease of 8% from Q4/18 levels. Including energy costs, Kirby South quarterly operating costs were $12.31/bbl in Q1/19, an increase of 35% from Q1/18 as a result of lower volumes and higher energy costs.
- As previously announced, at the Company's Kirby North SAGD project, top tier execution and strong productivity have resulted in the project progressing two quarters ahead of the sanctioned schedule with overall cost performance remaining on budget. The commissioning of the central processing facility was also top tier and as a result the project began steaming on May 1, 2019 and targets to progressively ramp up production towards Kirby North's overall capacity of 40,000 bbl/d, in late 2020.

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

North America Natural Gas

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Natural gas production (MMcf/d)	**1,454**	1,441	1,547
Net wells targeting natural gas	**9**	3	5
Net successful wells drilled	**8**	3	5
Success rate	**89%**	100%	100%

▪ North America natural gas production was 1,454 MMcf/d in Q1/19, in-line with Q4/18 levels.

▪ Operating costs of $1.30/Mcf were realized in Q1/19, in-line with Q1/18 levels.

▪ At the Company's high value Septimus Montney liquids rich area, 5 net wells were drilled in Q1/19 with targeted production of approximately 2,080 bbl/d of NGLs and approximately 30 MMcf/d of natural gas, in late Q2/19.

- Modest drilling activity from prolific wells targets to return the Septimus plant to full capacity, while reducing already low Q1/19 operating costs of $0.36/Mcfe, supporting high netbacks and maximizing value.
- The Company's natural gas reinjection pilot at Septimus is targeted to commence first injection of 5 MMcf/d late in Q2/19. This technology has the potential to materially increase liquids recovery while storing natural gas in the reservoir, preserving the value of the natural gas for periods with higher market prices.
  - ◦ Results from the first injection and production cycle are targeted for late 2019 with the potential to proceed with additional cycles at the same location. Given the opportunities for this process across Canadian Natural's vast liquids rich Montney land base, the Company is advancing readiness for a second pilot site within the Company's Greater Wembley area.

▪ Regulatory approval was received from the National Energy Board on May 3, 2019 regarding the transfer of assets to British Columbia provincial jurisdiction of the Pine River plant and operatorship to a subsidiary of Canadian Natural. The acquisition is targeted to close in Q2/19 and targets better plant efficiency and running time.

▪ In 2019, based upon the midpoint of annual production guidance, Canadian Natural targets to use the equivalent of approximately 37% of its total corporate natural gas production in its operations, providing a natural hedge from the challenging Western Canadian natural gas price environment. Approximately 34% of the Company's guided 2019 natural gas production is targeted to be exported to other North American markets and sold internationally. The remaining 29% of the Company's 2019 targeted natural gas production would be exposed to AECO/Station 2 pricing.

▪ The Company's annual 2019 corporate natural gas production guidance remains unchanged and is targeted to range between 1,485 MMcf/d - 1,545 MMcf/d.

International Exploration and Production

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil production (bbl/d)			
North Sea	**25,714**	21,071	21,584
Offshore Africa	**22,155**	22,185	19,438
Natural gas production (MMcf/d)			
North Sea	**28**	22	37
Offshore Africa	**28**	25	30
Net wells targeting crude oil	**1.6**	1.1	1.0
Net successful wells drilled	**1.6**	1.1	1.0
Success rate	**100%**	100%	100%

- International E&P quarterly production volumes were strong in Q1/19, averaging 47,869 bbl/d, increases of 11% and 17% from Q4/18 and Q1/18 levels, respectively, as described below. The operating costs below include impacts of IFRS 16.
- International production volumes benefit from premium Brent pricing, generating significant adjusted funds flow for the Company.
    - In the North Sea, production volumes of 25,714 bbl/d were achieved in Q1/19, increases of 22% and 19% over Q4/18 and Q1/19 levels respectively. The increase over Q4/18 primarily reflected the impact of production resuming following the planned turnarounds and maintenance activities completed during Q4/18. The increase over Q1/18 primarily reflected the impact of the drilling program completed in 2018, partially offset by natural field declines.
        - Q1/19 operating costs in the North Sea averaged $39.68/bbl (£22.60/bbl), a reduction of 9% from Q1/18 levels.
        - The 2019 drilling program consists of high value and high netback production additions from 3.8 net producer wells targeted in the North Sea. Drilling commenced in Q1/19 at the Ninian South Platform and late in the quarter 1.0 net well was completed on time and on budget. Production came on stream subsequent to quarter end and is exceeding expectations of 3,900 bbl/d.
        - The Company is targeting planned turnaround activities at the Ninian Central Platform late in Q2/19. Production impacts are reflected in Q2/19 and annual 2019 guidance.
    - Offshore Africa production volumes in Q1/19 averaged 22,155 bbl/d, in-line with Q4/18 levels and an increase of 14% over Q1/18 levels. The increase in production over Q1/18 primarily reflected volumes from new wells drilled at Baobab in 2018, partially offset by the cessation of production at the Olowi field in Gabon in December 2018 and natural field declines.
        - Côte d'Ivoire crude oil operating costs averaged $9.79/bbl (US$7.36/bbl) in Q1/19, a reduction of 3% from Q1/18 levels.
        - The Company completed the last 0.6 net producer well from the Baobab drilling program late in Q1/19. The drilling program resulted in current high netback production of approximately 8,000 bbl/d net, exceeding budgeted expectations.
            - The total Baobab drilling program included 4 gross (2.4 net) producer wells and 2 gross (1.2 net) injector wells, of which the second gross (0.6 net) injector well was completed subsequent to quarter end in Q2/19.
        - The Company targets to drill an appraisal well (0.6 net) at Kossipo in Q2/19, and if successful may lead to development drilling and a pipeline tied-back to the Baobab Floating Production Storage and Offloading vessel, adding significant future value with potential gross production capability of 20,000 bbl/d targeted in 2022.

- ◦ Following the successful completion of the Baobab drilling program, the Company targets to commence an additional high value drilling program in Q4/19 at Espoir, with initial production targeted for early 2020.
  - – The Espoir drilling program is targeting 3 gross producer wells (1.8 net) and 2 gross injector wells (1.2 net) with the potential to add an average of approximately 2,500 BOE/d of high netback production per well in the first 12 months. Approximately 75% of production is targeted to be light crude oil.
- ◦ In Q1/19, the operator of the South Africa exploration well, where Canadian Natural owns a 20% working interest, announced a discovery of significant gas condensate. The cost of the first exploration well is fully carried.
  - – In 2019, the operator targets to acquire 3D seismic on the Block.
  - – In 2020, the operator targets to drill a second exploration well and may drill two further exploration/ appraisal wells to further define volumes and deliverability.

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

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Synthetic crude oil production (bbl/d) (1) (2)	**416,206**	447,048	456,076

(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, industry leading operations provided quarterly production of 416,206 bbl/d of SCO, a decrease of 7% from Q4/18 levels. The decrease in production was primarily due to mandatory curtailments, previously announced accelerated maintenance activities as well as unplanned maintenance.
  - Operating costs were top tier, as the Company realized quarterly unadjusted operating costs of $21.46/bbl (US$16.14/bbl) of SCO in Q1/19, in-line with Q1/18 levels, strong results given curtailment and maintenance activities in the quarter.
- The Company continues to progress engineering work on the previously announced potential expansion and reliability opportunities at Horizon to increase reliability and lower costs, targeting to add production of 75,000 bbl/d to 95,000 bbl/d. The engineering and design specification work continued in the quarter and is targeted to be complete in Q3/19.
  - The potential Paraffinic Froth Treatment expansion at Horizon is targeting 40,000 bbl/d to 50,000 bbl/d of high quality diluted bitumen at significantly lower operating costs as the Company leverages its existing infrastructure. The preliminary estimate of the capital required is approximately $1.4 billion.
  - Stage 1 and 2 reliability opportunities at Horizon are targeted to add 35,000 bbl/d to 45,000 bbl/d of SCO.
  - The Company targets to sanction the potential expansion and reliability opportunities with greater clarity on improved market access.
- As previously announced on May 1, 2019, Canadian Natural provided a follow up on a fire which occurred at the Scotford Upgrader on April 15, 2019, in which the Company has a 70% interest. The fire was promptly extinguished, all personnel were accounted for, and there were no reported injuries.
  - The fire was contained to a process furnace in the North Upgrader, while operations at the base upgrader plant ("South Upgrader") were not impacted by the fire. The planned 38 day turnaround began on April 14, 2019 at the Scotford Upgrader, during which time the South Upgrader will run at a restricted net processing rate of approximately 140,000 bbl/d of SCO. Upon completion of the planned maintenance, May and June average net production at the Albian mines is targeted to be approximately 171,500 bbl/d versus the Company's previously targeted net curtailment production volumes at the Albian mines of approximately 178,500 bbl/d. The cost for repairs of the North Upgrader is estimated to be approximately $15 million gross and is targeted to be fully operational by early June. The Company continues to optimize other assets in Alberta to mitigate the impacts of curtailments on its production.

- The Company's annual 2019 Oil Sands Mining and Upgrading production guidance remains unchanged and is targeted to range between 415,000 bbl/d - 450,000 bbl/d of SCO.

MARKETING

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) [(1)]	**$ 54.90**	$ 58.83	$ 62.89
WCS heavy differential as a percentage of WTI (%) [(2)]	**23%**	67%	39%
SCO price (US$/bbl)	**$ 52.19**	$ 37.48	$ 61.45
Condensate benchmark pricing (US$/bbl)	**$ 50.49**	$ 45.27	$ 63.12
Average realized pricing before risk management (C$/bbl) [(3)]	**$ 53.98**	$ 25.95	$ 43.06
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 1.84**	$ 1.80	$ 1.75
Average realized pricing before risk management (C$/Mcf)	**$ 3.09**	$ 3.46	$ 2.74

(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.

- Q1/19 differentials between SCO and West Texas Intermediate ("WTI") benchmark pricing and Western Canadian Select ("WCS") and WTI benchmark pricing narrowed significantly to more normalized levels following the Government of Alberta's announcement of mandatory curtailments of crude oil production on December 2, 2018.
- AECO natural gas prices increased in Q1/19 from Q1/18 levels, reflecting the easing of third party pipeline constraints.
- The North West Redwater ("NWR") refinery, upon completion, will strengthen the Company's position by providing a competitive return on investment and by creating incremental demand for approximately 80,000 bbl/d of heavy crude oil blends that will not require export pipelines, helping to reduce pricing volatility in all Western Canadian heavy crude oil.
  - The Company has a 50% interest in the NWR Partnership. For updates on the project, please refer to: https://nwrsturgeonrefinery.com/whats-happening/news/.

ENVIRONMENTAL HIGHLIGHTS

- Canadian Natural has invested over $3.4 billion in research and development since 2009 and continues to invest in technology to unlock reserves, become more effective and efficient, increase production and reduce the Company's environmental footprint. Canadian Natural's culture of continuous improvement leverages the use of technology and innovation to drive sustainable operations and long-term value for shareholders.
- Canadian Natural has invested significant capital to capture and sequester CO_2. The Company has carbon capture and sequestration facilities at Horizon, a 70% working interest in the Quest Carbon Capture and Storage project at Scotford and carbon capture facilities at its 50% interest through the NWR refinery. As a result, Canadian Natural targets capacity to capture and sequester 2.7 million tonnes of CO_2 annually, equivalent to taking 576,000 vehicles off the road per year, making the Company one of the largest CO_2 capturer and sequester for the oil and natural gas sector globally once the NWR refinery is fully running.
- At Canadian Natural's Oil Sands Mining and Upgrading and thermal in situ operations, which represent approximately 65% of the Company's liquids production, the Company's emissions intensity is only approximately 5% higher than the average intensity for all global crude oils. By investing in and leveraging technology, including carbon capture initiatives, Canadian Natural has developed a pathway to reduce the Company's greenhouse gas emissions intensity to below the average for global crude oils.
- Canadian Natural's commitment to leverage technology, adopting innovation and continuous improvement is evidenced by its In Pit Extraction Process ("IPEP") pilot at Horizon, which will determine the feasibility of producing stackable dry tailings. The project has the potential to reduce the Company's carbon emissions and environmental

footprint by reducing the usage of haul trucks, the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to significantly reduce capital and operating costs.

- The initial testing phase for the Company's IPEP pilot has concluded and results have been positive with excellent recovery rates and evidence of stackable tailings. As a result of the positive results thus far, the Company continues to make enhancements and will operate and test the pilot through 2019.

FINANCIAL REVIEW

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

▪ The Company's strategy is to maintain a diverse portfolio balanced across various commodity types. The Company achieved production levels of 1,035,212 BOE/d in Q1/19, with approximately 97% of total production located in G7 countries.
  - Canadian Natural maintains a balance of products with Q1/19 production mix on a BOE/d basis of 54% light crude oil and SCO blends, 22% heavy crude oil blends and 24% natural gas.

▪ Canadian Natural delivered strong quarterly free cash flow of $860 million after net capital expenditures of $977 million and dividend requirements of $403 million, reflecting the strength of our long life low decline asset base and our effective and efficient operations.

▪ Canadian Natural maintains strong financial stability and liquidity represented by cash balances, and committed and demand bank credit facilities. At March 31, 2019 the Company had approximately $4,230 million of available liquidity, including cash and cash equivalents.

▪ Canadian Natural is committed to returns to shareholders, returning a total of $644 million in the quarter, $403 million by way of dividends and $241 million by way of share purchases.
  - Share purchases for cancellation in the quarter totaled 6,650,000 common shares at a weighted average share price $36.24. Subsequent to quarter end and up to and including May 8, 2019, the Company executed on additional share purchases of 4,050,000 common shares for cancellation at a weighted average share price of $39.34.
  - In Q1/19 the Company increased its quarterly dividend 12% from Q4/18 levels, marking the 19th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's sustainability and robustness of the asset base driving the ability to generate significant adjusted funds flow.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.375 per share, payable on July 1, 2019.

▪ In 2018, the Board of Directors approved a more defined free cash flow allocation policy in accordance with the Company's four stated pillars. Under the new policy, the Company will target to allocate, on an annual basis, 50% of its residual free cash flow, after budgeted capital expenditures and dividends, to share purchases under its NCIB and the remaining 50% to reducing debt levels on the Company's balance sheet. This free cash flow policy will target a ratio of debt to adjusted 12 months trailing EBITDA of 1.5x, and an absolute debt level of $15.0 billion, at which time the policy will be reviewed by the Board. This policy was effective November 1, 2018.
  - The Company's Board of Director's has approved a motion to renew the NCIB and the continuation of the free cash flow allocation policy.

▪ In addition to its strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. As at March 31, 2018, these financial levers include the Company's third party equity investments of $549 million, and cross currency swaps and foreign currency forward contracts with a total value of $266 million.

▪ All Q1/19 operating costs stated above reflect the impact of the adoption of IFRS 16. The lease liability recognized as required under IFRS 16 as a percentage of total enterprise value is approximately 2.4%, one of the lowest amongst the Company's Canadian peers, reflecting Canadian Natural's disciplined approach to managing longer term contractual arrangements.

OUTLOOK

The Company targets annual 2019 production levels to average between 782,000 bbl/d and 861,000 bbl/d of crude oil and NGLs and between 1,485 MMcf/d and 1,545 MMcf/d of natural gas, before royalties. Q2/19 production guidance before royalties is targeted to average between 773,000 bbl/d and 831,000 bbl/d of crude oil and NGLs and between 1,500 MMcf/d and 1,530 MMcf/d of natural gas. Detailed guidance on production levels, capital allocation and operating costs can be found on the Company's website at www.cnrl.com.

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

ADVISORY

Special Note Regarding Non-GAAP and other 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); net capital expenditures; free cash flow; debt to adjusted EBITDA; available liquidity; adjusted operating costs; unadjusted operating costs; and enterprise value. These financial measures are not defined by International Financial Reporting Standards ("IFRS") and therefore are referred to as non-GAAP measures and other financial measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows from operating activities, cash flows used in investing activities, and cash flows used in financing activities as determined in accordance with IFRS, as an indication of the Company's performance.

Adjusted net earnings (loss) from operations is a non-GAAP measure that represents net earnings (loss) as presented in the Company's consolidated Statements of Earnings (Loss), adjusted for the after-tax effects of certain items of a non-operational nature. The Company considers adjusted net earnings (loss) from operations a key measure in evaluating 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.

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 9 - Long-term Debt in the Company’s consolidated financial statements.

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

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

Enterprise value is derived as the sum of the Company’s market capitalization and total long-term debt less cash and cash equivalents. Market capitalization is derived as total outstanding common shares multiplied by the market price per common share at any given period.

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ADVISORY

Special Note Regarding Forward-Looking Statements

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

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

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

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

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

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow (previously referred to as funds flow from operations) 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 ended March 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 ended March 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 "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 for information purposes only.

The following discussion and analysis refers primarily to the Company's financial results for the three months ended March 31, 2019 in relation to the first quarter of 2018 and the fourth quarter of 2018. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2018, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com, provided that such guidance does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 8, 2019.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Product sales (1)	**$ 5,541**	$ 3,831	$ 5,735
Crude oil and NGLs	**$ 5,082**	$ 3,327	$ 5,303
Natural gas	**$ 456**	$ 504	$ 432
Net earnings (loss)	**$ 961**	$ (776)	$ 583
Per common share – basic	**$ 0.80**	$ (0.64)	$ 0.48
– diluted	**$ 0.80**	$ (0.64)	$ 0.47
Adjusted net earnings (loss) from operations (2)	**$ 838**	$ (255)	$ 885
Per common share – basic	**$ 0.70**	$ (0.21)	$ 0.72
– diluted	**$ 0.70**	$ (0.21)	$ 0.71
Cash flows from operating activities	**$ 996**	$ 1,397	$ 2,469
Adjusted funds flow (3)	**$ 2,240**	$ 1,229	$ 2,323
Per common share – basic	**$ 1.87**	$ 1.02	$ 1.90
– diluted	**$ 1.86**	$ 1.02	$ 1.89
Cash flows used in investing activities	**$ 1,029**	$ 1,042	$ 1,369
Net capital expenditures (4)	**$ 977**	$ 1,181	$ 1,103

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2019 are disclosed in note 17 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 acquisitions and abandonment expenditures. The Company considers net capital expenditures a key measure as it provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget. The reconciliation "Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities" is presented in the "Net Capital Expenditures" section of this MD&A. Net capital expenditures may not be comparable to similar measures presented by other companies.

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

	Three Months Ended		
($ millions)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Net earnings (loss), as reported	**$ 961**	$ (776)	$ 583
Share-based compensation, net of tax [1]	**62**	(148)	(88)
Unrealized risk management loss (gain), net of tax [2]	**13**	17	(31)
Unrealized foreign exchange (gain) loss, net of tax [3]	**(233)**	548	162
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax [4]	**—**	—	146
Loss from investments, net of tax [5] [6]	**35**	134	113
Gain on acquisition, disposition and revaluation of properties, net of tax [7]	**—**	(30)	—
Adjusted net earnings (loss) from operations	**$ 838**	$ (255)	$ 885

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

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

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

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

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

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

Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities [1]

	Three Months Ended		
($ millions)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Cash flows from operating activities	**$ 996**	$ 1,397	$ 2,469
Net change in non-cash working capital	**1,016**	(279)	(235)
Abandonment expenditures [2]	**108**	93	90
Other [3]	**120**	18	(1)
Adjusted funds flow	**$ 2,240**	$ 1,229	$ 2,323

(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 first quarter of 2019 were $961 million compared with net earnings of $583 million for the first quarter of 2018 and a net loss of $776 million for the fourth quarter of 2018. Net earnings for the first quarter of 2019 included net after-tax income of $123 million compared with net after-tax expenses of $302 million for the first quarter of 2018 and net after-tax expenses of $521 million for the fourth quarter of 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, and the gain on acquisition, disposition and revaluation of properties. Excluding these items, adjusted net earnings from operations for the first quarter of 2019 were $838 million compared with adjusted net earnings from operations of $885 million for the first quarter of 2018 and an adjusted net loss from operations of $255 million for the fourth quarter of 2018.

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

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

partially offset by:

- lower sales volumes in the North America Exploration and Production and Oil Sands Mining and Upgrading segments due to the impact of the Government of Alberta mandated production curtailments; and
- higher realized risk management losses.

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

- higher realized SCO prices in the Oil Sands Mining and Upgrading segment;
- higher crude oil and NGLs netbacks in the Exploration and Production segments; and
- lower depletion, depreciation and amortization in the Exploration and Production segments due to lower sales volumes;

partially offset by:

- lower sales volumes in the North America Exploration and Production and Oil Sands Mining and Upgrading segments due to the impact of the Government of Alberta mandated production curtailments; and
- higher realized risk management losses.

For the first quarter of 2019, the adoption of IFRS 16 did not have a significant overall impact on net earnings and adjusted net earnings from operations. The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings (loss). 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 first quarter of 2019 were $996 million compared with $2,469 million for the first quarter of 2018 and $1,397 million for the fourth quarter of 2018. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors noted above relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effect of depletion, depreciation and amortization), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2019 was $2,240 million compared with $2,323 million for the first quarter of 2018 and $1,229 million for the fourth quarter of 2018. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment 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 three months ended March 31, 2019 reflected an increase of $52 million related to the adoption of IFRS 16 on January 1, 2019. 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 first quarter of 2019 decreased 8% to 1,035,212 BOE/d from 1,123,546 BOE/d for the first quarter of 2018 and decreased 4% from 1,081,368 BOE/d for the fourth quarter of 2018, reflecting the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 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)	**Mar 31 2019**	Dec 31 2018	Sep 30 2018	Jun 30 2018
Product sales [1]	**$ 5,541**	$ 3,831	$ 6,327	$ 6,389
Crude oil and NGLs	**$ 5,082**	$ 3,327	$ 5,967	$ 6,071
Natural gas	**$ 456**	$ 504	$ 360	$ 318
Net earnings (loss)	**$ 961**	$ (776)	$ 1,802	$ 982
Net earnings (loss) per common share				
– basic	**$ 0.80**	$ (0.64)	$ 1.48	$ 0.80
– diluted	**$ 0.80**	$ (0.64)	$ 1.47	$ 0.80

($ millions, except per common share amounts)	Mar 31 2018	Dec 31 2017	Sep 30 2017	Jun 30 2017
Product sales	$ 5,735	$ 5,516	$ 4,725	$ 4,127
Crude oil and NGLs	$ 5,303	$ 5,098	$ 4,320	$ 3,645
Natural gas	$ 432	$ 418	$ 405	$ 482
Net earnings (loss)	$ 583	$ 396	$ 684	$ 1,072
Net earnings (loss) per common share				
– basic	$ 0.48	$ 0.32	$ 0.56	$ 0.93
– diluted	$ 0.47	$ 0.32	$ 0.56	$ 0.93

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2019 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from the Organization of the Petroleum Exporting Countries (“OPEC”) and its impact on world supply, the impact of geopolitical uncertainties on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"), the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company’s Primrose thermal projects, production from Kirby South, the results from the Pelican Lake water and polymer flood projects, the impact of the Company’s drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, production from Horizon Phase 3 as well as the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, voluntarily curtailed production 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 a third-party processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs that are dependent on weather, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, including the acquisition of AOSP and other assets, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, 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, fluctuations in depletion, depreciation and amortization expense in the North Sea due to the cessation of production at the Ninian North platform in the second quarter of 2017, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the determination of fair market value based on the Black-Scholes valuation model of the Company’s share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark - to - market and subsequent settlement of the Company’s risk management activities.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company received for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Income tax expense** – Fluctuations in income tax expense due to statutory tax rate and other legislative changes substantively enacted in the various periods.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of gains on the acquisition of AOSP and other assets, the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss (gain) on the Company's interest in the Redwater Partnership.

BUSINESS ENVIRONMENT

	Three Months Ended		
(Average for the period)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
WTI benchmark price (US$/bbl)	**$ 54.90**	$ 58.83	$ 62.89
Dated Brent benchmark price (US$/bbl)	**$ 63.34**	$ 67.45	$ 66.99
WCS heavy differential from WTI (US$/bbl)	**$ 12.38**	$ 39.36	$ 24.27
SCO price (US$/bbl)	**$ 52.19**	$ 37.48	$ 61.45
Condensate benchmark price (US$/bbl)	**$ 50.49**	$ 45.27	$ 63.12
Condensate differential from WTI (US$/bbl)	**$ 4.40**	$ 13.56	$ (0.23)
NYMEX benchmark price (US$/MMBtu)	**$ 3.16**	$ 3.65	$ 2.98
AECO benchmark price (C$/GJ)	**$ 1.84**	$ 1.80	$ 1.75
US/Canadian dollar average exchange rate (US$)	**$ 0.7522**	$ 0.7573	$ 0.7905

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$54.90 per bbl for the first quarter of 2019, a decrease of 13% from US$62.89 per bbl for the first quarter of 2018, and a decrease of 7% from US$58.83 per bbl for the fourth quarter of 2018. WTI pricing for the first quarter of 2019 decreased from the comparable periods primarily due to increased shale oil supply in the US.

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$63.34 per bbl for the first quarter of 2019, a decrease of 5% from US$66.99 per bbl for the first quarter of 2018, and a decrease of 6% from US$67.45 per bbl for the fourth quarter of 2018.

The WCS heavy differential averaged US$12.38 per bbl for the first quarter of 2019, a decrease of 49% from US$24.27 per bbl for the first quarter of 2018, and a decrease of 69% from US$39.36 per bbl for the fourth quarter of 2018. The narrowing of the WCS heavy differential for the first quarter of 2019 from the comparable periods primarily reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019. The WCS heavy differential in the first quarter of 2019 also reflected stronger US Gulf Coast heavy oil pricing due to supply shortfalls during the quarter.

The SCO price averaged US$52.19 per bbl for the first quarter of 2019, a decrease of 15% from US$61.45 per bbl for the first quarter of 2018, and an increase of 39% from US$37.48 per bbl for the fourth quarter of 2018. The decrease in SCO pricing for the first quarter of 2019 from the first quarter of 2018 primarily reflected a decrease in WTI benchmark pricing. The increase in SCO pricing for the first quarter of 2019 from the fourth quarter of 2018 reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

The condensate differential averaged a US$4.40 per bbl discount for the first quarter of 2019, compared to a US$0.23 per bbl premium for the first quarter of 2018, and a US$13.56 per bbl discount for the fourth quarter of 2018. The narrowing of the condensate differential for the first quarter of 2019 from the fourth quarter of 2018 reflected the impact of the Government of Alberta mandatory production curtailments that came into effect January 1, 2019.

NYMEX natural gas pricing averaged US$3.16 per MMBtu for the first quarter of 2019, an increase of 6% from US$2.98 per MMBtu for the first quarter of 2018 and a decrease of 13% from US$3.65 per MMBtu for the fourth quarter of 2018. The increase in NYMEX natural gas pricing for the first quarter of 2019 from the first quarter of 2018 reflected low storage inventory levels in North America. The decrease in NYMEX natural gas pricing for the first quarter of 2019 from the fourth quarter of 2018 reflected the impact of colder than normal weather conditions in the fourth quarter of 2018.

AECO natural gas pricing averaged $1.84 per GJ for the first quarter of 2019, an increase of 5% from $1.75 per GJ for the first quarter of 2018 and comparable with $1.80 per GJ for the fourth quarter of 2018. The increase in AECO natural gas pricing for the first quarter of 2019 from the first quarter of 2018 primarily reflected the easing of third party pipeline constraints.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**319,437**	343,054	357,460
North America – Oil Sands Mining and Upgrading [(1)]	**416,206**	447,048	456,076
North Sea	**25,714**	21,071	21,584
Offshore Africa	**22,155**	22,185	19,438
	783,512	833,358	854,558
Natural gas (MMcf/d)			
North America	**1,454**	1,441	1,547
North Sea	**28**	22	37
Offshore Africa	**28**	25	30
	1,510	1,488	1,614
Total barrels of oil equivalent (BOE/d)	**1,035,212**	1,081,368	1,123,546
Product mix			
Light and medium crude oil and NGLs	**14%**	13%	12%
Pelican Lake heavy crude oil	**6%**	6%	6%
Primary heavy crude oil	**7%**	7%	8%
Bitumen (thermal oil)	**9%**	10%	10%
Synthetic crude oil [(1)]	**40%**	41%	40%
Natural gas	**24%**	23%	24%
Percentage of gross revenue [(1) (2)] (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**91%**	85%	92%
Natural gas	**9%**	15%	8%

(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		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**281,233**	304,324	310,783
North America – Oil Sands Mining and Upgrading	**397,639**	421,421	443,606
North Sea	**25,675**	21,021	21,521
Offshore Africa	**20,260**	21,366	18,652
	724,807	768,132	794,562
Natural gas (MMcf/d)			
North America	**1,399**	1,396	1,473
North Sea	**28**	22	37
Offshore Africa	**25**	22	27
	1,452	1,440	1,537
Total barrels of oil equivalent (BOE/d)	**966,758**	1,008,210	1,050,702

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

Crude oil and NGLs production for the first quarter of 2019 decreased by 8% to average 783,512 bbl/d from 854,558 bbl/d for the first quarter of 2018, and decreased by 6% from 833,358 bbl/d for the fourth quarter of 2018.The decrease in crude oil and NGLs production for the first quarter of 2019 from the comparable periods primarily reflected the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. As a result of the mandated production curtailments, planned maintenance activities at Horizon were strategically advanced into the first quarter of 2019 from the second quarter of 2019. Decreased crude oil and NGLs production in the North America Exploration and Production and Oil Sands Mining and Upgrading segments was partially offset by increased production in the International segments due to the drilling programs completed in 2018.

First quarter 2019 crude oil and NGLs production was within the Company's previously issued guidance of 759,000 to 817,000 bbl/d. Second quarter 2019 crude oil and NGLs production guidance is targeted to average between 773,000 and 831,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through June 2019.

Natural gas production for the first quarter of 2019 of 1,510 MMcf/d decreased 6% from 1,614 MMcf/d for the first quarter of 2018, and was comparable with 1,488 MMcf/d for the fourth quarter of 2018. The decrease in natural gas production for the first quarter of 2019 from the first quarter of 2018 primarily reflected natural field declines and reduced drilling activity.

First quarter 2019 natural gas production was within the Company's previously issued guidance of 1,490 to 1,520 MMcf/d. Second quarter 2019 natural gas production guidance is targeted to average between 1,500 and 1,530 MMcf/d.

North America – Exploration and Production

North America crude oil and NGLs production for the first quarter of 2019 decreased by 11% to average 319,437 bbl/d from 357,460 bbl/d for the first quarter of 2018, and decreased by 7% from 343,054 bbl/d for the fourth quarter of 2018. The decrease in crude oil and NGLs production for the first quarter of 2019 from the comparable periods primarily reflected the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Operating performance at Pelican Lake continued to be strong, with heavy crude oil production averaging 61,240 bbl/day in the first quarter of 2019, compared with 63,274 bbl/d in the first quarter of 2018 and 62,428 bbl/d in the fourth quarter of 2018.

Overall thermal oil production for the first quarter of 2019 averaged 94,146 bbl/d compared with 111,851 bbl/d for the first quarter of 2018 and 102,112 bbl/d for the fourth quarter of 2018, reflecting the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. First quarter 2019 thermal oil production was within the Company's previously issued guidance of 92,000 to 98,000 bbl/d. Second quarter 2019 thermal oil production is targeted to average between 100,000 and 106,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through June 2019.

First quarter 2019 crude oil and NGLs production, including thermal oil, was within the Company's previously issued guidance of 313,000 to 327,000 bbl/d. Second quarter 2019 crude oil and NGLs production guidance, including thermal oil, is targeted to average between 324,000 and 338,000 bbl/d, reflecting known production curtailments mandated by the Government of Alberta through June 2019.

Natural gas production for the first quarter of 2019 decreased 6% to 1,454 MMcf/d from 1,547 MMcf/d for the first quarter of 2018, and was comparable with 1,441 MMcf/d for the fourth quarter of 2018. The decrease in natural gas production for the first quarter of 2019 from the first quarter of 2018 primarily reflected natural field declines and reduced drilling activity.

North America – Oil Sands Mining and Upgrading

SCO production for the first quarter of 2019 decreased 9% to average 416,206 bbl/d from 456,076 bbl/d for the first quarter of 2018 and decreased 7% from 447,048 bbl/d for the fourth quarter of 2018. The decrease in SCO production for the first quarter of 2019 from the comparable periods primarily reflected unplanned maintenance activities as well as the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. As a result of the mandated production curtailments, planned maintenance activities at Horizon were strategically advanced into the first quarter of 2019 from the second quarter of 2019.

First quarter 2019 SCO production was within the Company's previously issued guidance of 400,000 to 440,000 bbl/d. Second quarter 2019 SCO production guidance is targeted to average between 400,000 and 440,000 bbl/d, primarily reflecting planned maintenance activities, the impact of repairs related to the fire at the Scotford Upgrader, and to a lesser extent, the impact of known production curtailments mandated by the Government of Alberta through June 2019.

North Sea

North Sea crude oil production for the first quarter of 2019 increased 19% to 25,714 bbl/d from 21,584 bbl/d for the first quarter of 2018 and increased 22% from 21,071 bbl/d for the fourth quarter of 2018. The increase in production for the first quarter of 2019 from the first quarter of 2018 primarily reflected the impact of the drilling program completed in 2018, partially offset by natural field declines. The increase in production for the first quarter of 2019 from the fourth quarter of 2018 primarily reflected the impact of production resuming following the planned turnarounds and maintenance activities completed during the fourth quarter of 2018.

Offshore Africa

Offshore Africa crude oil production for the first quarter of 2019 increased 14% to 22,155 bbl/d from 19,438 bbl/d for the first quarter of 2018 and was comparable with 22,185 bbl/d for the fourth quarter of 2018. The increase in production for the first quarter of 2019 from the first quarter of 2018 primarily reflected volumes from new wells drilled at Baobab in 2018, partially offset by the cessation of production at the Olowi field, Gabon in December 2018 and natural field declines.

International Guidance

First quarter 2019 International crude oil production of 47,869 bbl/d was within the Company's previously issued guidance of 46,000 to 50,000 bbl/d. Second quarter 2019 crude oil production guidance is targeted to average between 49,000 and 53,000 bbl/d.

International Crude Oil Inventory Volumes

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

	Three Months Ended		
(bbl)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
North Sea	**851,919**	71,832	506,589
Offshore Africa	**1,055,383**	404,475	1,141,282
	1,907,302	476,307	1,647,871

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	**$ 53.98**	$ 25.95	$ 43.06
Transportation	**3.26**	2.94	3.10
Realized sales price, net of transportation	**50.72**	23.01	39.96
Royalties	**5.95**	0.92	4.87
Production expense	**16.04**	16.93	15.70
Netback	**$ 28.73**	$ 5.16	$ 19.39
Natural gas ($/Mcf) [1]			
Sales price [2]	**$ 3.09**	$ 3.46	$ 2.74
Transportation	**0.46**	0.42	0.51
Realized sales price, net of transportation	**2.63**	3.04	2.23
Royalties	**0.12**	0.10	0.10
Production expense	**1.33**	1.32	1.41
Netback	**$ 1.18**	$ 1.62	$ 0.72
Barrels of oil equivalent ($/BOE) [1]			
Sales price [2]	**$ 39.27**	$ 24.04	$ 32.02
Transportation	**3.06**	2.77	3.05
Realized sales price, net of transportation	**36.21**	21.27	28.97
Royalties	**3.78**	0.80	3.10
Production expense	**12.68**	13.51	12.68
Netback	**$ 19.75**	$ 6.96	$ 13.19

(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		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 50.92**	$ 17.03	$ 40.66
North Sea	**$ 87.61**	$ 78.45	$ 79.35
Offshore Africa	**$ 81.00**	$ 81.15	$ 78.85
Average	**$ 53.98**	$ 25.95	$ 43.06
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.88**	$ 3.23	$ 2.44
North Sea	**$ 10.05**	$ 14.09	$ 11.67
Offshore Africa	**$ 7.34**	$ 7.32	$ 6.95
Average	**$ 3.09**	$ 3.46	$ 2.74
Average ($/BOE) (1) (2)	**$ 39.27**	$ 24.04	$ 32.02

(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 averaged $50.92 per bbl for the first quarter of 2019, an increase of 25% compared with $40.66 per bbl for the first quarter of 2018 and an increase of 199% compared with $17.03 per bbl for the fourth quarter of 2018. The increase in realized crude oil prices for the first quarter of 2019 from the comparable periods 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 Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2019, contributed approximately 189,100 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 18% to average $2.88 per Mcf for the first quarter of 2019 compared with $2.44 per Mcf for the first quarter of 2018, and decreased 11% compared with $3.23 per Mcf for the fourth quarter of 2018. The increase in realized natural gas prices for the first quarter of 2019 compared with the first quarter of 2018 reflected low storage inventory levels in North America and the easing of third party pipeline constraints as well as higher natural gas export sales volumes and prices. The decrease in realized natural gas prices for the first quarter of 2019 compared with the fourth quarter of 2018 primarily reflected the impact of colder than normal weather conditions in the fourth quarter of 2018 as well as a slight decrease in export prices in the first quarter of 2019.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 49.13**	$ 34.62	$ 53.48
Pelican Lake heavy crude oil ($/bbl)	**$ 56.28**	$ 12.40	$ 41.63
Primary heavy crude oil ($/bbl)	**$ 52.27**	$ 11.33	$ 36.85
Bitumen (thermal oil) ($/bbl)	**$ 48.27**	$ 7.70	$ 32.22
Natural gas ($/Mcf)	**$ 2.88**	$ 3.23	$ 2.44

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

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

North Sea

North Sea realized crude oil prices increased 10% to average $87.61 per bbl for the first quarter of 2019 from $79.35 per bbl for the first quarter of 2018 and increased 12% from $78.45 per bbl for the fourth quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 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 increased 3% to average $81.00 per bbl for the first quarter of 2019 from $78.85 per bbl for the first quarter of 2018 and was comparable with $81.15 per bbl for the fourth quarter of 2018. Realized crude oil prices per bbl in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings of each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 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		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 6.22**	$ 0.82	$ 5.11
North Sea	**$ 0.13**	$ 0.18	$ 0.23
Offshore Africa	**$ 6.93**	$ 3.00	$ 3.19
Average	**$ 5.95**	$ 0.92	$ 4.87
Natural gas ($/Mcf) [1]			
North America	**$ 0.11**	$ 0.09	$ 0.09
Offshore Africa	**$ 0.85**	$ 0.80	$ 0.87
Average	**$ 0.12**	$ 0.10	$ 0.10
Average ($/BOE) [1]	**$ 3.78**	$ 0.80	$ 3.10

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

North America

North America crude oil and natural gas royalties for the first quarter of 2019 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS heavy differential.

Crude oil and NGLs royalty rates averaged approximately 12% of product sales for the first quarter of 2019 compared with 14% for the first quarter of 2018 and 6% for the fourth quarter of 2018. The decrease in royalty rates for the first quarter of 2019 from the first quarter of 2018 was primarily due to the underlying changes in the benchmark prices together with fluctuations in the WCS heavy differential. The increase in royalty rates for the first quarter of 2019 from the fourth quarter of 2018 reflected significantly higher crude oil prices following the Government of Alberta mandatory curtailment program that came into effect January 1, 2019.

Natural gas royalty rates averaged approximately 4% of product sales for the first quarter of 2019 compared with 5% for the first quarter of 2018 and 3% for the fourth quarter of 2018.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 9% for the first quarter of 2019, compared with 6% of product sales for the first quarter of 2018 and 4% for the fourth quarter of 2018. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2019	Dec 31 2018	Mar 31 2018
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 15.07**	$ 13.36	$ 14.15
North Sea	**$ 39.68**	$ 44.20	$ 43.39
Offshore Africa	**$ 9.79**	$ 32.15	$ 30.99
Average	**$ 16.04**	$ 16.93	$ 15.70
Natural gas ($/Mcf) (1)			
North America	**$ 1.30**	$ 1.23	$ 1.31
North Sea (2)	**$ 2.41**	$ 5.76	$ 4.67
Offshore Africa (2)	**$ 2.12**	$ 3.00	$ 2.44
Average	**$ 1.33**	$ 1.32	$ 1.41
Average ($/BOE) (1)	**$ 12.68**	$ 13.51	$ 12.68

(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 first quarter of 2019 reflected a decrease of $6 million ($2.28 per Mcf) and $1 million ($0.48 per Mcf) respectively, related to the adoption of IFRS 16.

North America

North America crude oil and NGLs production expense for the first quarter of 2019 of $15.07 per bbl increased 7% from $14.15 per bbl for the first quarter of 2018 and increased 13% from $13.36 per bbl for the fourth quarter of 2018. The increase in production expense per bbl for the first quarter of 2019 from the comparable periods reflected lower sales volumes due to the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019 and higher fuel and energy costs, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base. North America crude oil and NGLs production expense for the first quarter of 2019 reflected a decrease of $5 million ($0.18 per bbl) related to the adoption of IFRS 16.

North America natural gas production expense for the first quarter of 2019 of $1.30 per Mcf was comparable with $1.31 per Mcf for the first quarter of 2018 and increased 6% from $1.23 per Mcf for the fourth quarter of 2018. The increase in production expense for the first quarter of 2019 from the fourth quarter of 2018 primarily reflected the impact of seasonal conditions, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base. North America natural gas production expense for the first quarter of 2019 reflected a decrease of $1 million ($0.01 per Mcf) related to the adoption of IFRS 16.

North Sea

North Sea crude oil production expense for the first quarter of 2019 decreased 9% to $39.68 per bbl from $43.39 per bbl for the first quarter of 2018 and decreased 10% from $44.20 per bbl for the fourth quarter of 2018. The decrease in production expense per bbl for the first quarter of 2019 from the comparable periods primarily reflected the impact of higher volumes on a relatively fixed cost base. North Sea crude oil production expense for the first quarter of 2019 reflected a decrease of $1 million ($0.31 per bbl) related to the adoption of IFRS 16.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2019 decreased by 68% to $9.79 per bbl from $30.99 per bbl for the first quarter of 2018 and decreased by 70% from $32.15 per bbl for the fourth quarter of 2018. The decrease in crude oil production expense for the first quarter of 2019 from the comparable periods primarily reflected the cessation of production at the Olowi field, Gabon in December 2018. Crude oil production expense for the Baobab and Espoir fields in Côte d'Ivoire was $10.14 per bbl for the first quarter of 2018 and $11.68 per bbl for the fourth quarter of 2018. Production expense in Côte d'Ivoire for the first quarter of 2019 reflected a decrease of $2 million ($1.71 per bbl) related to the adoption of IFRS 16.

Crude oil production expense in Offshore Africa was also impacted by the timing of liftings from the various fields, which have different cost structures, fluctuating production volumes on a relatively fixed cost base and fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense	**$ 843**	$ 929	$ 850
$/BOE [1]	**$ 15.54**	$ 15.50	$ 14.66

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

The decrease in depletion, depreciation and amortization expense for the first quarter of 2019 from the comparable periods primarily reflected the impact of lower sales volumes in the first quarter of 2019, partially offset by an increase of $31 million related to the adoption of IFRS 16.

Depletion, depreciation and amortization expense per BOE for the first quarter of 2019 increased 6% to $15.54 per BOE from $14.66 per BOE for the first quarter of 2018 and was comparable with $15.50 per BOE for the fourth quarter of 2018. The increase in depletion, depreciation and amortization expense per BOE for the first quarter of 2019 from the comparable periods reflected the adoption of IFRS 16, partially offset by lower depletion rates in Offshore Africa and North America. Depletion, depreciation and amortization expense for the first quarter of 2019 reflected an increase of $0.57 per BOE related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense	**$ 28**	$ 31	$ 31
$/BOE [1]	**$ 0.54**	$ 0.52	$ 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 first quarter of 2019 of $0.54 per BOE increased 2% from $0.53 per BOE for the first quarter of 2018 and increased 4% from $0.52 per BOE for the fourth quarter of 2018. The increase in asset retirement obligation accretion expense per BOE for the first quarter of 2019 from the comparable periods primarily reflected lower sales volumes during the first quarter of 2019.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the sites. Production in the first quarter of 2019 averaged 416,206 bbl/d, reflecting unplanned maintenance activities and the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019. As a result of the mandated production curtailments, planned maintenance activities at Horizon were strategically advanced into the first quarter of 2019 from the second quarter of 2019. Through the Company's continuous focus on cost control and efficiencies, high utilization rates and reliability of operations, production costs averaged $21.46 per bbl during the quarter.

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

	Three Months Ended		
($/bbl) (1)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
SCO realized sales price (2)	**$ 65.86**	$ 42.73	$ 71.61
Bitumen value for royalty purposes (3)	**$ 48.16**	$ 29.93	$ 31.48
Bitumen royalties (4)	**$ 2.31**	$ 2.03	$ 1.98
Transportation	**$ 1.17**	$ 1.56	$ 1.54

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price for the Oil Sands Mining and Upgrading segment averaged $65.86 per bbl for the first quarter of 2019, a decrease of 8% from $71.61 per bbl for the first quarter of 2018 and an increase of 54% from $42.73 per bbl for the fourth quarter of 2018. The decrease in the realized SCO sales price for the first quarter of 2019 from the first quarter of 2018 primarily reflected WTI benchmark pricing. The increase in the realized SCO sales price for the first quarter of 2019 from the fourth quarter of 2018 primarily reflected the impact of the Government of Alberta mandated production curtailments that came into effect January 1, 2019.

Transportation expense for the Oil Sands Mining and Upgrading segment averaged $1.17 per bbl for the first quarter of 2019, compared with $1.54 per bbl for the first quarter of 2018 and $1.56 per bbl for the fourth quarter of 2018. Transportation expense for the first quarter of 2019 reflected a decrease of $14 million ($0.37 per bbl) related to the adoption of IFRS 16.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

($ millions)	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Production costs, excluding natural gas costs	**$ 779**	$ 773	$ 835
Natural gas costs	**43**	24	38
Production costs	**$ 822**	$ 797	$ 873

($/bbl) [(1)]	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Production costs, excluding natural gas costs	**$ 20.33**	$ 19.37	$ 20.45
Natural gas costs	**1.13**	0.60	0.92
Production costs	**$ 21.46**	$ 19.97	$ 21.37
Sales (bbl/d)	**425,790**	433,970	453,850

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

Production costs for the first quarter of 2019 averaged $21.46 per bbl, comparable with $21.37 per bbl for the first quarter of 2018 and an increase of 7% from $19.97 per bbl for the fourth quarter of 2018. The increase in production costs per bbl for the first quarter of 2019 from the fourth quarter of 2018 primarily reflected lower production volumes due to unplanned maintenance activities and the impact of the Government of Alberta mandated production curtailments, together with higher fuel and energy costs. Production costs for the first quarter of 2019 reflected a decrease of $7 million ($0.17 per bbl) related to the adoption of IFRS 16.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Expense	**$ 417**	$ 396	$ 404
$/bbl [(1)]	**$ 10.88**	$ 9.92	$ 9.88

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

Depletion, depreciation and amortization expense per bbl for the first quarter of 2019 increased 10% to $10.88 per bbl from $9.88 per bbl for the first quarter of 2018 and increased 10% from $9.92 per bbl for the fourth quarter of 2018. The increase in depletion, depreciation and amortization expense per bbl for the first quarter of 2019 from the comparable periods was primarily due to the impact of fluctuations in sales volumes from different underlying operations, with a higher proportion of sales in the first quarter of 2019 subject to a higher depletion rate, compared to the previous periods. Depletion, depreciation and amortization expense for the first quarter of 2019 reflected an increase of $19 million ($0.49 per bbl) related to the adoption of IFRS 16.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense	**$ 16**	$ 15	$ 15
$/bbl (1)	**$ 0.41**	$ 0.38	$ 0.38

(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 of $0.41 per bbl for the first quarter of 2019 increased 8% from $0.38 per bbl for the first quarter of 2018 and the fourth quarter of 2018, primarily due to lower sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended		
($ millions)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Revenue	**$ 21**	$ 24	$ 27
Less:			
Production expense	**6**	5	5
Depreciation	**3**	3	3
Equity loss from investment	**60**	—	1
Segment earnings (loss) before taxes	**$ (48)**	$ 16	$ 18

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

During 2018, Redwater Partnership commenced commissioning activities in the Projects' 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. The Project's bitumen refining operations have been delayed and remain in the commissioning phase due to design modifications to the reactor burners in the gasifier unit and to address stress cracking identified in certain stainless steel piping. Currently, the heavy oil units are expected to commence commercial processing of bitumen in late 2019. As at March 31, 2019, the total facility capital cost ("FCC") budget for the Project, net of margins from pre-commercial sales, totaled approximately $9,800 million.

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 March 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $167 million, for a Company total of $606 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at March 31, 2019, the Company had recognized $81 million in prepaid cost of service tolls (December 31, 2018 – $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2020. As at March 31, 2019, Redwater Partnership had borrowings of $2,288 million under the credit facility.

During the three months ended March 31, 2019, the Company recognized an equity loss from Redwater Partnership of $60 million (December 31, 2018 – $nil, March 31, 2018 – loss of $1 million). The equity loss for the first quarter of 2019 includes the impact of $47 million of interest expense and $12 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense	**$ 70**	$ 91	$ 81
$/BOE (1)	**$ 0.76**	$ 0.91	$ 0.82

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

Administration expense for the first quarter of 2019 of $0.76 per BOE decreased 7% from $0.82 per BOE for the first quarter of 2018 and decreased 16% from $0.91 per BOE for the fourth quarter of 2018. Administration expense per BOE decreased for the first quarter of 2019 from the comparable periods due to lower personnel and other corporate costs in the first quarter of 2019. Administration expense for the first quarter of 2019 reflected a decrease of $6 million ($0.06 per BOE) related to the adoption of IFRS 16.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense (recovery)	**$ 62**	$ (148)	$ (88)

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

The Company recorded a $62 million share-based compensation expense for the first quarter of 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 first quarter of 2019 was an expense of $10 million related to performance share units granted to certain executive employees (March 31, 2018 – $1 million). For the first quarter of 2019, the Company charged $1 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (March 31, 2018 – $13 million costs recovered).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
Expense, gross	**$ 211**	$ 198	$ 205
Less: capitalized interest	**20**	19	15
Expense, net	**$ 191**	$ 179	$ 190
$/BOE (1)	**$ 2.06**	$ 1.78	$ 1.92
Average effective interest rate	**4.1%**	4.1%	3.8%

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

Gross interest and other financing expense for the first quarter of 2019 included an increase of $15 million due to interest expense on lease liabilities recognized due to the adoption of IFRS 16. Capitalized interest of $20 million for the first quarter of 2019 was primarily related to the Kirby North project and residual project activities at Horizon.

Net interest and other financing expense per BOE for the first quarter of 2019 increased 7% to $2.06 per BOE from $1.92 per BOE for the first quarter of 2018 and increased 16% from $1.78 per BOE for the fourth quarter of 2018. The increase in net interest and other financing expense per BOE for the first quarter of 2019 from the comparable periods primarily reflected the adoption of IFRS 16. The increase from the fourth quarter of 2018 also reflected the impact of lower sales volumes in the first quarter of 2019. Net interest and other financing expense per BOE for the first quarter of 2019 reflected an increase of $0.17 per BOE related to the adoption of IFRS 16.

The Company's average effective interest rate for the first quarter of 2019 increased from the first quarter of 2018 primarily due to the impact of higher benchmark interest rates on the Company's outstanding bank credit facilities.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
Crude oil and NGLs financial instruments	**$ 28**	$ (27)	$ —
Natural gas financial instruments	**(1)**	2	—
Foreign currency contracts	**—**	(20)	(19)
Realized loss (gain)	**27**	(45)	(19)
Crude oil and NGLs financial instruments	**5**	41	—
Natural gas financial instruments	**—**	(6)	—
Foreign currency contracts	**9**	(8)	(33)
Unrealized loss (gain)	**14**	27	(33)
Net loss (gain)	**$ 41**	$ (18)	$ (52)

During the first quarter of 2019, the net realized risk management loss was related to the settlement of crude oil and NGLs financial instruments. The Company recorded a net unrealized loss of $14 million ($13 million after-tax) on its risk management activities for the first quarter of 2019 (three months ended December 31, 2018 – unrealized loss of $27 million; $17 million after-tax; three months ended March 31, 2018 – unrealized gain of $33 million; $31 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2019 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
Net realized (gain) loss	**$ (6)**	$ (2)	$ 116
Net unrealized (gain) loss	**(233)**	548	162
Net (gain) loss [(1)]	**$ (239)**	$ 546	$ 278

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

The net realized foreign exchange gain for the first quarter of 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 first quarter of 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 March 31, 2019 – unrealized loss of $30 million, December 31, 2018 – unrealized gain of $76 million, March 31, 2018 – unrealized gain of $40 million). The US/Canadian dollar exchange rate at March 31, 2019 was US$0.7485 (December 31, 2018 – US$0.7328, March 31, 2018 – US$0.7751).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended **Mar 31 2019**	Dec 31 2018	Mar 31 2018
North America [1]	**$ 163**	$ (254)	$ 150
North Sea	**29**	8	1
Offshore Africa	**12**	11	5
PRT [2] – North Sea	**(42)**	—	(4)
Other taxes	**3**	1	2
Current income tax expense (recovery)	**165**	(234)	154
Deferred corporate income tax expense	**94**	112	127
Deferred PRT [2] – North Sea	**—**	(1)	10
Deferred income tax expense	**94**	111	137
	$ 259	$ (123)	$ 291
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**26%**	33%	24%

(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 first quarter of 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 PRT recovery in the North Sea for the first quarter of 2019 and comparable periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

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

For 2019, current income tax expense is now targeted to range from $600 million to $800 million in Canada and $75 million to $100 million in the North Sea and Offshore Africa.

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended Mar 31 2019	Dec 31 2018	Mar 31 2018
Exploration and Evaluation			
Net expenditures (proceeds)	**$ 33**	$ (95)	$ 56
Property, Plant and Equipment			
Net property acquisitions	**24**	1	162
Well drilling, completion and equipping	**254**	359	321
Production and related facilities	**287**	365	264
Capitalized interest and other [2]	**29**	32	23
Net expenditures	**594**	757	770
Total Exploration and Production	**627**	662	826
Oil Sands Mining and Upgrading			
Project costs [3]	**76**	178	66
Sustaining capital	**140**	235	105
Turnaround costs	**8**	12	13
Capitalized interest and other [2]	**10**	(8)	(5)
Total Oil Sands Mining and Upgrading	**234**	417	179
Midstream and Refining	**2**	2	4
Abandonments [4]	**108**	93	90
Head office	**6**	7	4
Total net capital expenditures	**$ 977**	$ 1,181	$ 1,103
By segment			
North America	**$ 524**	$ 604	$ 772
North Sea	**36**	58	35
Offshore Africa	**67**	—	19
Oil Sands Mining and Upgrading	**234**	417	179
Midstream and Refining	**2**	2	4
Abandonments [4]	**108**	93	90
Head office	**6**	7	4
Total	**$ 977**	$ 1,181	$ 1,103

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

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

(4) 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		
($ millions)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Cash flows used in investing activities	***$ 1,029***	*$ 1,042*	*$ 1,369*
Net change in non-cash working capital	***(160)***	*46*	*(335)*
Investment in other long-term assets	**—**	*—*	*(21)*
Abandonment expenditures (1)	***108***	*93*	*90*
Net capital expenditures	***$ 977***	*$ 1,181*	*$ 1,103*

(1) 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 first quarter of 2019 were $977 million compared with $1,103 million for the first quarter of 2018 and $1,181 million for the fourth quarter of 2018. Net capital expenditures for the first quarter of 2019 were consistent with the Company's previously announced capital allocation schedule.

Drilling Activity (1)

	Three Months Ended		
(number of wells)	**Mar 31 2019**	Dec 31 2018	Mar 31 2018
Net successful natural gas wells	**8**	3	5
Net successful crude oil wells (2)	**30**	102	122
Dry wells	**1**	2	2
Stratigraphic test / service wells	**332**	91	450
Total	**371**	198	579
Success rate (excluding stratigraphic test / service wells)	**97%**	98%	98%

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

(2) Includes bitumen wells.

North America

During the first quarter of 2019, the Company targeted 9 net natural gas wells, 7 net primary heavy crude oil wells and 21 net light crude oil wells.

North Sea

During the first quarter of 2019, the Company completed one gross light crude oil well (1.0 on a net basis) in the North Sea.

Offshore Africa

During the first quarter of 2019, the Company completed one gross light crude oil well and one gross injection well (combined 1.2 on a net basis) at Baobab.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		Mar 31 2019		Dec 31 2018		Mar 31 2018
Working capital (1)	**$**	**319**	$	(601)	$	702
Long-term debt (2) (3)	**$**	**20,990**	$	20,623	$	21,978
Less: cash and cash equivalents		**90**		101		152
Long-term debt, net	**$**	**20,900**	$	20,522	$	21,826
Share capital	**$**	**9,358**	$	9,323	$	9,264
Retained earnings		**22,852**		22,529		22,785
Accumulated other comprehensive income (loss)		**58**		122		(23)
Shareholders' equity	**$**	**32,268**	$	31,974	$	32,026
Debt to book capitalization (3) (4)		**39.3%**		39.1%		40.5%
Debt to market capitalization (3) (5)		**32.2%**		34.1%		30.5%
After-tax return on average common shareholders' equity (6)		**9.2%**		8.0%		8.7%
After-tax return on average capital employed (3) (7)		**6.6%**		5.9%		6.0%

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

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

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

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

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

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

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

As at March 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:
  - Borrowings under the 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 March 31, 2019, the non-revolving term credit facilities were fully drawn.

- Each of the $2,425 million revolving syndicated credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under these facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its bank credit facilities for amounts outstanding under this program.
- In July 2017, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire in August 2019. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

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

As at March 31, 2019, the Company had in place revolving bank credit facilities of $4,976 million, of which $4,142 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. This excludes certain other dedicated credit facilities supporting letters of credit.

As at March 31, 2019, the Company had total US dollar denominated debt with a carrying amount of $14,835 million (US $11,106 million), before transaction costs and original issue discounts. This included $6,015 million (US$4,506 million) hedged by way of cross currency swaps (US$1,050 million) and foreign currency forwards (US$3,456 million). The fixed repayment amount of these hedging instruments is $5,760 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $255 million to $14,580 million as at March 31, 2019.

Net long-term debt was $20,900 million at March 31, 2019, resulting in a debt to book capitalization ratio of 39.3% (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 March 31, 2019 are discussed in note 8 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 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 March 31, 2019, 8,000 bbl/d of currently forecasted crude oil volumes were hedged using WCS differential swaps for April to September 2019, as well as 115,000 GJ/d of currently forecasted natural gas volumes using AECO fixed price swaps for April to October 2019. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2019 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

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

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 1,667	$ 6,689	$ 5,101	$ 7,647
Other long-term liabilities (2)	$ 260	$ 200	$ 390	$ 857
Interest and other financing expense (3)	$ 909	$ 768	$ 1,760	$ 5,255

(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, $211 million; one to less than two years, $176 million; two to less than five years, $345 million; and thereafter, $857 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 March 31, 2019.

Share Capital

As at March 31, 2019, there were 1,197,653,000 common shares outstanding (December 31, 2018 – 1,201,886,000 common shares) and 53,353,000 stock options outstanding. As at May 7, 2019, the Company had 1,194,744,000 common shares outstanding and 51,970,000 stock options outstanding.

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

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

For the three months ended March 31, 2019, the Company purchased for cancellation 6,650,000 common shares at a weighted average price of $36.24 per common share for a total cost of $241 million. Retained earnings were reduced by $189 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2019, the Company purchased 4,050,000 common shares at a weighted average price of $39.34 per common share for a total cost of $159 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has various commitments that will have an impact on the Company's future operations. The following table summarizes the Company's commitments as at March 31, 2019 (1):

	Remaining 2019	2020	2021	2022	2023	Thereafter
Product transportation	$ 416	$ 544	$ 516	$ 445	$ 325	$ 3,436
North West Redwater Partnership service toll (2)	$ 57	$ 126	$ 157	$ 158	$ 157	$ 2,858
Offshore vessels and equipment	$ 63	$ 81	$ 65	$ 9	$ —	$ —
Field equipment and power	$ 26	$ 20	$ 21	$ 20	$ 21	$ 274
Other	$ 37	$ 20	$ 19	$ 16	$ 16	$ 47

(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) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,272 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 also to the audited consolidated financial statements for the year ended December 31, 2018 and the unaudited interim financial statements for the three months ended March 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 (less than 12 months) and low-value leases (as defined in the standard) are exempt from the requirements, and the Company continues to treat these leases as expenses. Leases to explore for or use crude oil, natural gas, minerals and similar non-regenerative resources are also exempt from the standard.

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

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

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 were treated as short-term leases;
- exclusion of indirect 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.

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 March 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 ended March 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 portion of lease payments, previously classified as cash flows from operating activities is now reported as an investing activity;
- Increased depletion, depreciation and amortization expense and interest expense;
- Decreased production expense, transportation expense and administration expense; and
- Commitments for leases, previously reported in the "Commitments and Contingencies" section of this MD&A, are now reported in the maturity table in the 'Liquidity and Capital Resources' section of this MD&A.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. Actual results could differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the 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 three months ended March 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.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2019	Dec 31 2018
ASSETS			
Current assets			
Cash and cash equivalents		**$ 90**	$ 101
Accounts receivable		**2,287**	1,148
Inventory		**1,072**	955
Prepaids and other		**192**	176
Investments	6	**549**	524
Current portion of other long-term assets	7	**73**	116
		4,263	3,020
Exploration and evaluation assets	3	**2,652**	2,637
Property, plant and equipment	4	**64,126**	64,559
Lease assets	5	**1,584**	—
Other long-term assets	7	**1,343**	1,343
		$ 73,968	$ 71,559
LIABILITIES			
Current liabilities			
Accounts payable		**$ 779**	$ 779
Accrued liabilities		**2,559**	2,356
Current income taxes payable		**59**	151
Current portion of long-term debt	8	**1,667**	1,141
Current portion of other long-term liabilities	5,9	**547**	335
		5,611	4,762
Long-term debt	8	**19,323**	19,482
Other long-term liabilities	5,9	**5,232**	3,890
Deferred income taxes		**11,534**	11,451
		41,700	39,585
SHAREHOLDERS' EQUITY			
Share capital	11	**9,358**	9,323
Retained earnings		**22,852**	22,529
Accumulated other comprehensive income	12	**58**	122
		32,268	31,974
		$ 73,968	$ 71,559

Commitments and contingencies (note 16).

Approved by the Board of Directors on May 8, 2019.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2019	Mar 31 2018
Product sales	17	**$ 5,541**	$ 5,735
Less: royalties		**(293)**	(261)
Revenue		**5,248**	5,474
Expenses			
Production		**1,530**	1,630
Transportation, blending and feedstock		**1,039**	1,152
Depletion, depreciation and amortization	4,5	**1,263**	1,257
Administration		**70**	81
Share-based compensation	9	**62**	(88)
Asset retirement obligation accretion	9	**44**	46
Interest and other financing expense		**191**	190
Risk management activities	15	**41**	(52)
Foreign exchange (gain) loss		**(239)**	278
Loss from investments	6,7	**27**	106
		4,028	4,600
Earnings before taxes		**1,220**	874
Current income tax expense	10	**165**	154
Deferred income tax expense	10	**94**	137
Net earnings		**$ 961**	$ 583
Net earnings per common share			
Basic	14	**$ 0.80**	$ 0.48
Diluted	14	**$ 0.80**	$ 0.47

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2019	Mar 31 2018
Net earnings	**$ 961**	$ 583
Items that may be reclassified subsequently to net earnings		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income (loss) during the period, net of taxes of $5 million (2018 – $2 million)	**29**	(16)
Reclassification to net earnings, net of taxes of $5 million (2018 – $2 million)	**(33)**	(10)
	(4)	(26)
Foreign currency translation adjustment		
Translation of net investment	**(60)**	71
Other comprehensive income (loss), net of taxes	**(64)**	45
Comprehensive income	**$ 897**	$ 628

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2019	Mar 31 2018
Share capital	11		
Balance – beginning of period		**$ 9,323**	$ 9,109
Issued upon exercise of stock options		**83**	106
Previously recognized liability on stock options exercised for common shares		**4**	49
Purchase of common shares under Normal Course Issuer Bid		**(52)**	—
Balance – end of period		**9,358**	9,264
Retained earnings			
Balance – beginning of period		**22,529**	22,612
Net earnings		**961**	583
Purchase of common shares under Normal Course Issuer Bid	11	**(189)**	—
Dividends on common shares	11	**(449)**	(410)
Balance – end of period		**22,852**	22,785
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**122**	(68)
Other comprehensive income (loss), net of taxes		**(64)**	45
Balance – end of period		**58**	(23)
Shareholders' equity		**$ 32,268**	$ 32,026

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended	
(millions of Canadian dollars, unaudited)	Note	**Mar 31 2019**	Mar 31 2018
Operating activities			
Net earnings		**$ 961**	$ 583
Non-cash items			
Depletion, depreciation and amortization		**1,263**	1,257
Share-based compensation		**62**	(88)
Asset retirement obligation accretion		**44**	46
Unrealized risk management loss (gain)		**14**	(33)
Unrealized foreign exchange (gain) loss		**(233)**	162
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	146
Loss from investments	6,7	**35**	113
Deferred income tax expense		**94**	137
Other		**(120)**	1
Abandonment expenditures		**(108)**	(90)
Net change in non-cash working capital		**(1,016)**	235
Cash flows from operating activities		**996**	2,469
Financing activities			
Issue of bank credit facilities and commercial paper, net	8	**635**	381
Repayment of US dollar debt securities	8	**—**	(1,236)
Payment of lease liabilities	5,9	**(52)**	—
Issue of common shares on exercise of stock options		**83**	106
Purchase of common shares under Normal Course Issuer Bid	11	**(241)**	—
Dividends on common shares		**(403)**	(336)
Cash flows from (used in) financing activities		**22**	(1,085)
Investing activities			
Net expenditures on exploration and evaluation assets		**(33)**	(56)
Net expenditures on property, plant and equipment		**(836)**	(957)
Investment in other long-term assets		**—**	(21)
Net change in non-cash working capital		**(160)**	(335)
Cash flows used in investing activities		**(1,029)**	(1,369)
(Decrease) increase in cash and cash equivalents		**(11)**	15
Cash and cash equivalents – beginning of period		**101**	137
Cash and cash equivalents – end of period		**$ 90**	$ 152
Interest paid, net		**$ 228**	$ 260
Income taxes paid (received)		**$ 226**	$ (63)

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. ACCOUNTING POLICIES

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

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

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

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

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

2. CHANGES IN ACCOUNTING POLICIES

IFRS 16 "Leases"

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

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

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

- the use of a single discount rate to a portfolio of leases with reasonably similar characteristics;
- leases with a remaining lease term of less than twelve months as at January 1, 2019 were treated as short-term leases;
- exclusion of indirect 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 March 31, 2019 are shown in note 5.

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

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

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

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

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

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

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

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

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

Changes in other accounting policies

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

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

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2018	$ 2,348	$ —	$ 37	$ 252	$ 2,637
Additions	**30**	**—**	**3**	**—**	**33**
Transfers to property, plant and equipment	**(18)**	**—**	**—**	**—**	**(18)**
At March 31, 2019	**$ 2,360**	**$ —**	**$ 40**	**$ 252**	**$ 2,652**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2018	$ 67,007	$ 7,321	$ 5,471	$ 43,147	$ 441	$ 435	$ 123,822
Additions	**501**	**36**	**64**	**234**	**2**	**6**	**843**
Transfers from E&E assets	**18**	**—**	**—**	**—**	**—**	**—**	**18**
Disposals/derecognitions	**(126)**	**—**	**(1,515)**	**(84)**	**—**	**(3)**	**(1,728)**
Foreign exchange adjustments and other	**—**	**(154)**	**(140)**	**—**	**—**	**—**	**(294)**
At March 31, 2019	**$ 67,400**	**$ 7,203**	**$ 3,880**	**$ 43,297**	**$ 443**	**$ 438**	**$ 122,661**
Accumulated depletion and depreciation							
At December 31, 2018	$ 43,881	$ 5,735	$ 4,203	$ 4,981	$ 138	$ 325	$ 59,263
Expense	**719**	**46**	**42**	**398**	**3**	**6**	**1,214**
Disposals/derecognitions	**(126)**	**—**	**(1,515)**	**(84)**	**—**	**(3)**	**(1,728)**
Foreign exchange adjustments and other	**(2)**	**(109)**	**(97)**	**(6)**	**—**	**—**	**(214)**
At March 31, 2019	**$ 44,472**	**$ 5,672**	**$ 2,633**	**$ 5,289**	**$ 141**	**$ 328**	**$ 58,535**
Net book value							
- at March 31, 2019	**$ 22,928**	**$ 1,531**	**$ 1,247**	**$ 38,008**	**$ 302**	**$ 110**	**$ 64,126**
- at December 31, 2018	$ 23,126	$ 1,586	$ 1,268	$ 38,166	$ 303	$ 110	$ 64,559

Project costs not subject to depletion and depreciation	**Mar 31 2019**	Dec 31 2018
Kirby Thermal Oil Sands – North	**$ 1,509**	$ 1,424

During the three months ended March 31, 2019, the Company acquired a number of producing crude oil and natural gas properties in the North America Exploration and Production segment for net cash consideration of $25 million and assumed associated asset retirement obligations of $5 million. These transactions were accounted for using the acquisition method of accounting. No net deferred income tax liabilities or pre-tax gains were recognized on these transactions.

The Company capitalizes construction period interest for qualifying assets based on costs incurred and the Company's cost of borrowing. Interest capitalization to a qualifying asset ceases once the asset is substantially available for its intended use. For the three months ended March 31, 2019, pre-tax interest of $20 million (March 31, 2018 – $15 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 4.1% (March 31, 2018 – 3.8%).

5. LEASES

Lease assets

		Product transportation and storage		Field equipment and power		Offshore vessels and equipment		Office leases and other		Total
At January 1, 2019 [1]	$	823	$	332	$	252	$	132	$	1,539
Additions		**107**		**3**		**—**		**—**		**110**
Depreciation		**(22)**		**(12)**		**(10)**		**(5)**		**(49)**
Foreign exchange adjustments and other		**(1)**		**(3)**		**(12)**		**—**		**(16)**
At March 31, 2019	**$**	**907**	**$**	**320**	**$**	**230**	**$**	**127**	**$**	**1,584**

(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

		Mar 31 2019
Exploration and Production		
North America	**$**	**312**
North Sea		**60**
Offshore Africa		**180**
Oil Sands Mining and Upgrading		**922**
Head office		**110**
	$	**1,584**

Lease liabilities

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

		Mar 31 2019
Lease liabilities	**$**	**1,589**
Less: current portion		**211**
	$	**1,378**

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. The impact of short-term leasing activities on net earnings for the period is provided below:

Three months ended	Mar 31 2019
Expenses relating to short-term leases (1)	$ 124
Interest expense on lease liabilities	$ 15
Variable lease payments not included in the measurement of lease liabilities	$ 24

(1) In addition, during the first quarter of 2019, the Company capitalized $81 million of short-term leases as additions to property, plant and equipment.

Three months ended	Mar 31 2019
Total cash outflows for leases during the period (1)	$ 296

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

Impacts to the consolidated financial statements on transition

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

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

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

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

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

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

6. INVESTMENTS

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

		Mar 31 2019		Dec 31 2018
Investment in PrairieSky Royalty Ltd.	**$**	**407**	$	400
Investment in Inter Pipeline Ltd.		**142**		124
	$	**549**	$	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 March 31, 2019, the Company's investment in PrairieSky was classified as a current asset.

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

	Three Months Ended			
		Mar 31 2019		Mar 31 2018
Fair value (gain) loss from PrairieSky	**$**	**(7)**	$	88
Dividend income from PrairieSky		**(5)**		(4)
	$	**(12)**	$	84

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 March 31, 2019, the Company's investment in Inter Pipeline was classified as a current asset.

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

	Three Months Ended			
		Mar 31 2019		Mar 31 2018
Fair value (gain) loss from Inter Pipeline	**$**	**(18)**	$	24
Dividend income from Inter Pipeline		**(3)**		(3)
	$	**(21)**	$	21

7. OTHER LONG-TERM ASSETS

		Mar 31 2019		Dec 31 2018
Investment in North West Redwater Partnership	$	227	$	287
North West Redwater Partnership subordinated debt (1)		606		591
Risk management (note 15)		270		373
Prepaid cost of service tolls		81		62
Other		232		146
		1,416		1,459
Less: current portion		73		116
	$	1,343	$	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 Projects' 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. The Project's bitumen refining operations have been delayed and remain in the commissioning phase and are now expected to commence commercial processing of bitumen in late 2019. As at March 31, 2019, the total facility capital cost ("FCC") budget for the Project, net of margins from pre-commercial sales, was approximately $9,800 million.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. To March 31, 2019, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $167 million, for a Company total of $606 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 16). The Company is unconditionally obligated to pay this portion of the cost of service toll over the 30-year tolling period. As at March 31, 2019, the Company had recognized $81 million in prepaid cost of service tolls (December 31, 2018 - $62 million).

Redwater Partnership has a secured $3,500 million syndicated credit facility of which $2,000 million is revolving and matures in June 2021 and the remaining $1,500 million is fully drawn on a non-revolving basis and matures in February 2020. As at March 31, 2019, Redwater Partnership had borrowings of $2,288 million under the credit facility.

During the three months ended March 31, 2019, the Company recognized an equity loss from Redwater Partnership of $60 million (March 31, 2018 – loss of $1 million). The equity loss for the first quarter of 2019 includes the impact of $47 million of interest expense and $12 million of depletion, depreciation and amortization expense recognized following the completion of commissioning and startup activities in the light oil units.

8. LONG-TERM DEBT

		Mar 31 2019		Dec 31 2018
Canadian dollar denominated debt, unsecured				
Bank credit facilities	$	969	$	831
Medium-term notes		5,300		5,300
		6,269		6,131
US dollar denominated debt, unsecured				
Bank credit facilities (March 31, 2019 - US$2,956 million; December 31, 2018 - US$2,954 million)		3,948		4,031
Commercial paper (March 31, 2019 - US$500 million; December 31, 2018 - US$104 million)		667		141
US dollar debt securities (March 31, 2019 - US$7,650 million; December 31, 2018 - US$7,650 million)		10,220		10,439
		14,835		14,611
Long-term debt before transaction costs and original issue discounts, net		21,104		20,742
Less: original issue discounts, net (1)		17		17
transaction costs (1) (2)		97		102
		20,990		20,623
Less: current portion of commercial paper		667		141
current portion of other long-term debt (1) (2)		1,000		1,000
	$	19,323	$	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 March 31, 2019, the Company had in place revolving bank credit facilities of $4,976 million, as described below, of which $4,142 million was available. Additionally, the Company had in place fully drawn term credit facilities of $4,750 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

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

Borrowings under the 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 March 31, 2019, the non-revolving facilities were fully drawn.

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

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

The Company’s weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2019 was 2.6% (March 31, 2018 – 2.5%), and on total long-term debt outstanding for the three months ended March 31, 2019 was 4.1% (March 31, 2018 – 3.8%).

As at March 31, 2019, letters of credit and guarantees aggregating $434 million were outstanding.

Medium-Term Notes

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

US Dollar Debt Securities

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

9. OTHER LONG-TERM LIABILITIES

		Mar 31 2019		Dec 31 2018
Asset retirement obligations	$	3,812	$	3,886
Share-based compensation		183		124
Lease liabilities (note 5)		1,589		—
Risk management (note 15)		24		17
Deferred purchase consideration (1)		94		118
Other		77		80
		5,779		4,225
Less: current portion		547		335
	$	5,232	$	3,890

(1) Includes $94 million of deferred purchase consideration at March 31, 2019 (December 31, 2018 - $118 million), 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 5.0% (December 31, 2018 – 5.0%) and inflation rates of up to 2% (December 31, 2018 - up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

		Mar 31 2019		Dec 31 2018
Balance – beginning of period	$	3,886	$	4,327
Liabilities incurred		2		19
Liabilities acquired, net		5		6
Liabilities settled		(108)		(290)
Asset retirement obligation accretion		44		186
Revision of cost, inflation rates and timing estimates		—		(111)
Change in discount rate		—		(334)
Foreign exchange adjustments		(17)		83
Balance – end of period		3,812		3,886
Less: current portion		146		186
	$	3,666	$	3,700

Share-Based Compensation

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

	Mar 31 2019	Dec 31 2018
Balance – beginning of period	**$ 124**	$ 414
Share-based compensation expense (recovery)	**62**	(146)
Cash payment for stock options surrendered	**—**	(5)
Transferred to common shares	**(4)**	(120)
Charged to (recovered from) Oil Sands Mining and Upgrading, net	**1**	(19)
Balance – end of period	**183**	124
Less: current portion	**129**	92
	$ 54	$ 32

Included within share-based compensation liability as at March 31, 2019 was $23 million related to performance share units granted to certain executive employees (December 31, 2018 - $13 million).

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
Expense (recovery)	**Mar 31 2019**	Mar 31 2018
Current corporate income tax – North America	**$ 163**	$ 150
Current corporate income tax – North Sea	**29**	1
Current corporate income tax – Offshore Africa	**12**	5
Current PRT [1] – North Sea	**(42)**	(4)
Other taxes	**3**	2
Current income tax	**165**	154
Deferred corporate income tax	**94**	127
Deferred PRT [1] – North Sea	**—**	10
Deferred income tax	**94**	137
Income tax	**$ 259**	$ 291

(1) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2019	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,201,886**	**$ 9,323**
Issued upon exercise of stock options	**2,417**	**83**
Previously recognized liability on stock options exercised for common shares	**—**	**4**
Purchase of common shares under Normal Course Issuer Bid	**(6,650)**	**(52)**
Balance – end of period	**1,197,653**	**$ 9,358**

Dividend Policy

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

On March 6, 2019, the Board of Directors declared a quarterly dividend of $0.375 per common share, an increase from the previous quarterly dividend of $0.335 per common share. The dividend is payable on April 1, 2019.

Normal Course Issuer Bid

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

For the three months ended March 31, 2019, the Company purchased 6,650,000 common shares at a weighted average price of $36.24 per common share for a total cost of $241 million. Retained earnings were reduced by $189 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2019, the Company purchased 4,050,000 common shares at a weighted average price of $39.34 per common share for a total cost of $159 million.

Stock Options

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

	Three Months Ended Mar 31, 2019	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**46,685**	**$ 37.92**
Granted	**10,857**	**$ 35.85**
Surrendered for cash settlement	**(581)**	**$ 35.23**
Exercised for common shares	**(2,417)**	**$ 34.24**
Forfeited	**(1,191)**	**$ 37.30**
Outstanding – end of period	**53,353**	**$ 37.70**
Exercisable – end of period	**16,398**	**$ 36.39**

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

12. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

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

		Mar 31 2019		Mar 31 2018
Derivative financial instruments designated as cash flow hedges	**$**	**9**	$	21
Foreign currency translation adjustment		**49**		(44)
	$	**58**	$	(23)

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At March 31, 2019, the ratio was within the target range at 39.3%.

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.

		Mar 31 2019		Dec 31 2018
Long-term debt, net [(1)]	**$**	**20,900**	$	20,522
Total shareholders' equity	**$**	**32,268**	$	31,974
Debt to book capitalization		**39.3%**		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 March 31, 2019, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

	Three Months Ended			
		Mar 31 2019		Mar 31 2018
Weighted average common shares outstanding – basic (thousands of shares)		**1,200,948**		1,225,618
Effect of dilutive stock options (thousands of shares)		**2,339**		5,718
Weighted average common shares outstanding – diluted (thousands of shares)		**1,203,287**		1,231,336
Net earnings	**$**	**961**	$	583
Net earnings per common share – basic	**$**	**0.80**	$	0.48
– diluted	**$**	**0.80**	$	0.47

15. FINANCIAL INSTRUMENTS

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

	Mar 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	**$ 2,287**	**$ —**	**$ —**	**$ —**	**$ 2,287**
Investments	**—**	**549**	**—**	**—**	**549**
Other long-term assets	**606**	**4**	**266**	**—**	**876**
Accounts payable	**—**	**—**	**—**	**(779)**	**(779)**
Accrued liabilities	**—**	**—**	**—**	**(2,559)**	**(2,559)**
Other long-term liabilities (1)	**—**	**(24)**	**—**	**(1,683)**	**(1,707)**
Long-term debt (2)	**—**	**—**	**—**	**(20,990)**	**(20,990)**
	$ 2,893	**$ 529**	**$ 266**	**$ (26,011)**	**$ (22,323)**

	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 $94 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:

	Mar 31, 2019			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 549**	**$ 549**	**$ —**	**$ —**
Other long-term assets	**$ 876**	**$ —**	**$ 270**	**$ 606**
Other long-term liabilities	**$ (118)**	**$ —**	**$ (24)**	**$ (94)**
Fixed rate long-term debt (6) (7)	**$ (15,406)**	**$ (16,556)**	**$ —**	**$ —**

	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 liquid nature of the asset or liability (cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities, and purchase consideration payable), as well as lease liabilities, where carrying amount approximates fair value.

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

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

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

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

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

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

Risk Management

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

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

Asset (liability)	**Mar 31 2019**	Dec 31 2018
Derivatives held for trading		
Foreign currency forward contracts	**$ (3)**	$ 8
Crude oil WCS [1] differential swaps	**(21)**	(17)
Natural gas AECO fixed price swaps	**4**	3
Natural gas AECO basis swaps	**—**	1
Cash flow hedges		
Foreign currency forward contracts	**8**	70
Cross currency swaps	**258**	291
	$ 246	$ 356
Included within:		
Current portion of other long-term assets	**$ 21**	$ 92
Current portion of other long-term liabilities	**(24)**	(17)
Other long-term assets	**249**	281
	$ 246	$ 356

(1) Western Canadian Select

For the three months ended March 31, 2019, the Company recognized a gain of $1 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 forward interest rate yield curves, and Canadian and United States foreign exchange rates, discounted to present value as appropriate. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

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

Asset (liability)		**Mar 31 2019**		Dec 31 2018
Balance – beginning of period	**$**	**356**	$	101
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**(14)**		35
Foreign exchange		**(92)**		260
Other comprehensive loss		**(4)**		(40)
Balance – end of period		**246**		356
Less: current portion		**(3)**		75
	$	**249**	$	281

Net losses (gains) from risk management activities were as follows:

	Three Months Ended			
		Mar 31 2019		Mar 31 2018
Net realized risk management loss (gain)	**$**	**27**	$	(19)
Net unrealized risk management loss (gain)		**14**		(33)
	$	**41**	$	(52)

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 March 31, 2019, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term			Volume	Weighted average price	Index
Crude Oil						
WCS differential swaps	Apr 2019	—	Sep 2019	8,000 bbl/d	US$23.57	WCS
Natural Gas						
AECO fixed price swaps	Apr 2019	—	Oct 2019	115,000 GJ/d	$1.32	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 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 March 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	Apr 2019	—	Nov 2021	US$500	1.022	3.45%	3.96%
	Apr 2019	—	Mar 2038	US$550	1.170	6.25%	5.76%

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

In addition to the cross currency swap contracts noted above, at March 31, 2019, the Company had US$3,946 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,456 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 March 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 March 31, 2019, the Company had net risk management assets of $256 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 financial 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
Accounts payable	$	779	$	—	$	—	$	—
Accrued liabilities	$	2,559	$	—	$	—	$	—
Long-term debt (1)	$	1,667	$	6,689	$	5,101	$	7,647
Other long-term liabilities (2)	$	260	$	200	$	390	$	857
Interest and other financing expense (3)	$	909	$	768	$	1,760	$	5,255

(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, $211 million; one to less than two years, $176 million; two to less than five years, $345 million; and thereafter, $857 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 March 31, 2019.

16. COMMITMENTS AND CONTINGENCIES

The Company has committed to certain payments as follows (1):

		Remaining 2019		2020		2021		2022		2023		Thereafter
Product transportation	$	416	$	544	$	516	$	445	$	325	$	3,436
North West Redwater Partnership service toll (2)	$	57	$	126	$	157	$	158	$	157	$	2,858
Offshore vessels and equipment	$	63	$	81	$	65	$	9	$	—	$	—
Field equipment and power	$	26	$	20	$	21	$	20	$	21	$	274
Other	$	37	$	20	$	19	$	16	$	16	$	47

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

(2) Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service toll, which currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service toll is $1,272 million of interest payable over the 30 year tolling period. See note 7.

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

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

17. SEGMENTED INFORMATION

	North America		North Sea		Offshore Africa		Total Exploration and Production	
	Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31	
(millions of Canadian dollars, unaudited)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales								
Crude oil and NGLs	**1,839**	1,842	**134**	109	**109**	58	**2,082**	2,009
Natural gas	**375**	340	**25**	39	**18**	19	**418**	398
Other [(1)]	**2**	—	**—**	—	**1**	—	**3**	—
Total segmented product sales	**2,216**	2,182	**159**	148	**128**	77	**2,503**	2,407
Less: royalties	**(193)**	(175)	**—**	—	**(11)**	(5)	**(204)**	(180)
Segmented revenue	**2,023**	2,007	**159**	148	**117**	72	**2,299**	2,227
Segmented expenses								
Production	**602**	631	**67**	75	**18**	29	**687**	735
Transportation, blending and feedstock	**524**	734	**6**	6	**1**	1	**531**	741
Depletion, depreciation and amortization	**743**	778	**54**	44	**46**	28	**843**	850
Asset retirement obligation accretion	**20**	22	**7**	7	**1**	2	**28**	31
Risk management activities (commodity derivatives)	**31**	—	**—**	—	**—**	—	**31**	—
Equity loss from investment	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**1,920**	2,165	**134**	132	**66**	60	**2,120**	2,357
Segmented earnings (loss) before the following	**103**	(158)	**25**	16	**51**	12	**179**	(130)
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management activities (other)								
Foreign exchange (gain) loss								
(Gain) loss from investments								
Total non–segmented expenses								
Earnings before taxes								
Current income tax expense								
Deferred income tax expense								
Net earnings								

	Oil Sands Mining and Upgrading		Midstream and Refining		Inter–segment elimination and other		Total	
	Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31		Three Months Ended Mar 31	
(millions of Canadian dollars, unaudited)	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Segmented product sales								
Crude oil and NGLs	**2,854**	3,198	**21**	27	**125**	69	**5,082**	5,303
Natural gas	**—**	—	**—**	—	**38**	34	**456**	432
Other (1)	**—**	—	**—**	—	**—**	—	**3**	—
Total segmented product sales	**2,854**	3,198	**21**	27	**163**	103	**5,541**	5,735
Less: royalties	**(89)**	(81)	**—**	—	**—**	—	**(293)**	(261)
Segmented revenue	**2,765**	3,117	**21**	27	**163**	103	**5,248**	5,474
Segmented expenses								
Production	**822**	873	**6**	5	**15**	17	**1,530**	1,630
Transportation, blending and feedstock	**360**	325	**—**	—	**148**	86	**1,039**	1,152
Depletion, depreciation and amortization	**417**	404	**3**	3	**—**	—	**1,263**	1,257
Asset retirement obligation accretion	**16**	15	**—**	—	**—**	—	**44**	46
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**31**	—
Equity loss from investment	**—**	—	**60**	1	**—**	—	**60**	1
Total segmented expenses	**1,615**	1,617	**69**	9	**163**	103	**3,967**	4,086
Segmented earnings (loss) before the following	**1,150**	1,500	**(48)**	18	**—**	—	**1,281**	1,388
Non–segmented expenses								
Administration							**70**	81
Share-based compensation							**62**	(88)
Interest and other financing expense							**191**	190
Risk management activities (other)							**10**	(52)
Foreign exchange (gain) loss							**(239)**	278
(Gain) loss from investments							**(33)**	105
Total non–segmented expenses							**61**	514
Earnings before taxes							**1,220**	874
Current income tax expense							**165**	154
Deferred income tax expense							**94**	137
Net earnings							**961**	583

(1) 'Other' includes recoveries associated with the joint operation partners' share of the costs of lease contracts, and other income of a trivial nature.

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2019			Mar 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	**$ 30**	**$ (18)**	**$ 12**	$ 50	$ (29)	$ 21
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**3**	**—**	**3**	6	—	6
	$ 33	**$ (18)**	**$ 15**	$ 56	$ (29)	$ 27
Property, plant and equipment						
Exploration and Production						
North America	**$ 494**	**$ (101)**	**$ 393**	$ 722	$ (48)	$ 674
North Sea	**36**	**—**	**36**	35	—	35
Offshore Africa [3]	**64**	**(1,515)**	**(1,451)**	13	—	13
	594	**(1,616)**	**(1,022)**	770	(48)	722
Oil Sands Mining and Upgrading [4]	**234**	**(84)**	**150**	179	(32)	147
Midstream and Refining	**2**	**—**	**2**	4	—	4
Head office	**6**	**(3)**	**3**	4	—	4
	$ 836	**$ (1,703)**	**$ (867)**	$ 957	$ (80)	$ 877

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

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

(3) Offshore Africa includes a derecognition of $1,515 million following the FPSO demobilization at the Olowi field, Gabon in the first quarter of 2019.

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

Segmented Assets

	Mar 31 2019	Dec 31 2018
Exploration and Production		
North America	**$ 27,811**	$ 27,199
North Sea	**1,699**	1,699
Offshore Africa	**1,508**	1,471
Other	**98**	33
Oil Sands Mining and Upgrading	**41,196**	39,634
Midstream and Refining	**1,436**	1,413
Head office	**220**	110
	$ 73,968	$ 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 2017. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the three month period ended March 31, 2019:	
Interest coverage (times)	
Net earnings (1)	5.7x
Adjusted funds flow (2)	12.5x

(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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Vice-President and Managing Director, International

Barry Duncan
Vice-President, Finance, International

Stock Listing

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

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