FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2020 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2020 FIRST QUARTER RESULTS

Commenting on the Company's first quarter 2020 results, Tim McKay, President of Canadian Natural stated, "Through the first quarter of 2020 and in response to the outbreak of the novel coronavirus ("COVID-19"), we have taken proactive and effective steps to ensure the safety and health of our employees, service providers and the communities we work in, while maintaining safe, reliable operations. We currently have approximately 6,000 employees working remotely and approximately 4,000 field personnel working under safety protocols with minimal impact to our operations.

Canadian Natural is in a strong position. Our vast and diverse asset base is robust, unique and sustainable. The effectiveness of our strategies and our ability to execute on those strategies allows us to react quickly in this challenging commodity price environment. Our long life low decline assets have industry leading breakeven prices as a result of low sustaining capital requirements, effective and efficient operations, low operating costs and low to no reservoir risk, a distinct advantage in volatile price environments. As a result, a small percentage of our total proved reserves are produced during challenging commodity price periods, resulting in very little impact to net asset value, thereby preserving long-term value for our stakeholders.

In Q1/20, we delivered top tier operational results, producing our maximum allowable volumes under the Government of Alberta curtailment program, achieving record quarterly corporate production of approximately 1,179 MBOE/d, including record liquids production of approximately 939 Mbbl/d. Importantly, we increased the level of high value Synthetic Crude Oil ("SCO") production in the quarter, maximizing adjusted funds flow.

We target to effectively and efficiently manage through the current environment. Our balance sheet is strong with significant liquidity available and our 2020 capital program is disciplined at approximately \$2.7 billion, having executed on approximately \$1.4 billion in reductions. Targeted operating cost reductions from 2019 levels are significant in 2020, at approximately \$745 million and the Board of Directors has maintained our current dividend levels, demonstrating their confidence in the Company's assets and plan moving forward."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added, "In Q1/20, we have been proactive in managing our balance sheet and executing on our capital flexibility, given the volatility in commodity prices. To date, including the most recent reduction in the capital expenditure forecast, we have reduced our targeted capital expenditures by approximately \$1.4 billion in 2020 from the original budget announced in December 2019, while at the same time targeting to increase crude oil and natural gas production over 2019 levels. In Q1/20, our strong adjusted funds flow of over \$1.3 billion was in excess of our capital expenditures and dividend requirements. Our liquidity at the end of Q1/20 remains robust at approximately \$5.0 billion, including approximately \$1.1 billion in cash reserves and our balance sheet remains resilient through this commodity price cycle and supported by strong investment grade credit ratings."

COPORATE UPDATE

COVID-19 Response

- Canadian Natural has taken proactive and effective steps to ensure the safety and health of our employees, service providers and communities where we work during the outbreak of the novel coronavirus ("COVID-19"), some of which are over and above guidance from the Public Health Agency of Canada and provincial health authorities.
  - Canadian Natural's proactive measures are allowing for continued effective and efficient operations with minimal impact to the Company's operations at its head office and in the field, both Internationally and in North America. Currently the Company has approximately 6,000 employees working remotely and approximately 4,000 field personnel working under safety protocols to maintain safe reliable operations.
  - Canadian Natural has pandemic response and business continuity plans in place to protect the health and safety of our personnel while maintaining safe, reliable operations and supporting the aggressive measures being taken by public health officials to limit the spread of COVID-19.
  - Canadian Natural monitors government updates daily and follows the guidance of public health officials. As the situation with COVID-19 evolves, the Company has enhanced precautionary measures and ensured actions are implemented and followed. Precautionary measures are currently in effect across the Company's work locations. Canadian Natural will continue to strengthen these measures at the advice of public health officials as needed.

Balance Sheet Strength and Liquidity

- Canadian Natural is in a robust overall financial position with strong liquidity. The Company continues to manage effectively through the current short term commodity price environment. As at March 31, 2020, the Company had approximately $5.0 billion of liquidity available, an increase of $116 million over Q4/19 levels. Liquidity is represented by cash and cash equivalents of approximately $1.1 billion and committed bank credit facilities. The liquidity is more than sufficient to retire, when due, any upcoming debt maturities.
- Subsequent to quarter end, the Company's $750 million non-revolving term credit facility, originally due February 2021 was increased by $250 million to $1,000 million and extended to February 2022, further increasing liquidity.
- Canadian Natural continues to maintain strong investment grade credit ratings. The Company has a high degree of communication with credit rating agencies to ensure they understand the robust and sustainable nature of the Company's assets. Their understanding is evident in the following results:
  - On March 20, 2020, Moody’s Investors Service, Inc. (“Moody’s”) affirmed the Company's long term and short term investment grade credit ratings of Baa2 and P-2 with a stable outlook.
  - On March 26, 2020, Standard & Poor’s Rating Services (“S&P”) rating action on the Company resulted in long term and short term investment grade credit ratings of BBB and A-2 with a stable outlook.
  - DBRS Limited (“DBRS”) current credit rating for the Company is BBB high.

Production Flexibility

- Canadian Natural’s vast and diverse asset base is robust, unique and sustainable. The Company has a significant advantage during volatile pricing scenarios because its long life low decline assets have low sustaining capital requirements, low operating costs and low to no reservoir risk. This results in the Company producing an immaterial percentage of its total proved reserves during challenged commodity price periods, resulting in very little impact to net asset value, thereby preserving value for all of the Company's stakeholders.
- In Q1/20, the Company effectively executed on its curtailment optimization strategy within the Government of Alberta curtailment guidelines and achieved maximum allowable production, resulting in record production volumes. Production was optimized across the asset base to produce the highest value products, maximizing the Company's netback and adjusted funds flow.
- Canadian Natural continues to be prudent and proactive in managing its production volumes. The current operating plan is targeting to reduce well servicing activity and to shut-in higher cost volumes in North America Conventional E&P business. In addition the Company targets to temporarily curtail production in its thermal in situ assets. The majority of these volumes can be brought back on quickly when commodity prices recover. Details are as follows:
  - North America Conventional E&P crude oil production volumes are targeted to be approximately 36,000 bbl/d lower in May 2020 than it would be in a more normalized price environment, as the Company has shut-in high variable cost volumes and stopped well servicing activities.

- Thermal in situ production volumes are targeted to be approximately 38,000 bbl/d lower in May 2020 than it would be in a more normalized price environment, as the Company has temporarily slowed down production volumes and is conducting planned maintenance activities.

- The Company's strength of operations and diverse asset base allows Canadian Natural to optimize activities within its Oil Sands Mining and Upgrading assets as follows:
  - Canadian Natural has planned routine de-coking activities at Horizon that were deferred from Q1/20 to May 2020 which will result in Horizon volumes being 50,000 bbl/d lower than normal in the month, running at restricted rates.
  - In the second half of 2020, the Company is targeting planned turnaround activities at both AOSP and Horizon mines. The Company has the flexibility to shift timelines to ensure minimal, if any overlapping activities between the two sites, maximizing high value SCO production and operating cash flows. Details are as follows:
    - At the non-operated Scotford Upgrader, a turnaround is targeted for early in Q3/20, at which time the plant will run at restricted rates. Timing of these activities at the AOSP mines are aligned with the planned turnaround at the Scotford Upgrader. During the turnaround, production from AOSP is targeted to average approximately 100,000 bbl/d net lower than normal, in the months of July 2020 and August 2020.
    - At Horizon, the planned turnaround is targeted for the second half of 2020. Monthly average production is targeted to be impacted by approximately 80,000 bbl/d over a two month period once timing is finalized.
- Canadian Natural's natural gas portfolio is significant, providing the Company with additional production flexibility and opportunities to maximize value as prices improve. The Company has identified a number of highly economic opportunities to add additional natural gas volumes at less than $3,000 per flowing BOE. These activities are targeted to add approximately 60 MMcf/d of natural gas volumes, which equates to approximately 35 MMcf/d for 2020 annual natural gas production levels.
  - Canadian Natural's natural gas volumes provide significant supportive operating cash flow, targeted at approximately $700 million over the next twelve months at AECO pricing of $2.50/GJ.
- Due to the current uncertainty around the COVID-19 pandemic, the Company is officially removing its 2020 corporate production guidance. However, if the current strip pricing continues for the remainder of 2020, the Company forecasts that targeted production will meet the previous issued corporate guidance range.

Operating Cost Reductions

- Canadian Natural has top tier operating costs and as a result of the Company's culture of innovation, continued focus on effective and efficient operations and continuous improvement, Canadian Natural is targeting to lower operating costs throughout 2020 by approximately $745 million versus 2019 levels.

($ million)	2019	2020 Forecast	2020 Targeted Operating Costs Savings
North America Natural Gas	$ 610	$ 575	$ 35
North America E&P Liquids (excluding Thermal) (1)	1,230	930	300
Thermal In Situ (1)	865	795	70
International	500	410	90
Oil Sands Mining and Upgrading	3,275	3,025	250
Total Targeted Operating Cost Savings			$ 745

(1) 2019 includes proforma full-year of Jackfish using an average of 100,000 bbl/d of production and pre-acquisition operating costs of $12.00/bbl and Manatokan heavy crude oil using an average of 20,000 bbl/d of production and pre-acquisition operating costs of $16.00/bbl.

- As previously announced, the Company has taken proactive steps to reduce administrative expenses. The Company targets an approximate reduction of $90 million in G&A compared to the original 2020 budget.

Capital Flexibility

- The Company has executed on additional capital flexibility, reducing its 2020 capital expenditure budget by an additional $280 million beyond the March 18, 2020 update. Capital expenditures are now targeted to be approximately $2,680 million, a $1,370 million reduction from the Company's original 2020 budget released in December 2019. A summary of the 2020 targeted capital budget by area is as follows:

($ million)		2020 Original Budget		2020 Original Revision		2020 Current Forecast
Conventional/Unconventional	$	1,550	$	990	$	875
Long Life Low Decline	$	2,500	$	1,970	$	1,805
Total	$	4,050	$	2,960	$	2,680

- 2020 capital expenditure requirements are targeted to be approximately $1.8 billion to be deployed over the last three quarters.
- Canadian Natural's flexibility and ability to be nimble was evident in Q1/20 as net capital expenditures were reduced quickly by approximately $200 million from the original Q1/20 capital budget.

Dividend Update

- Canadian Natural's business is unique, robust and sustainable. The strength of the Company's assets and its ability to generate significant and sustainable free cash flow over the long term combined with strong liquidity, production flexibility, significant capital reductions and targeted operating costs savings provided the Board of Directors with the confidence that the Company's current dividend levels can be sustained through the commodity price cycle.
    - As previously announced, on March 5, 2020 the Company declared a quarterly dividend increase of 13% to $0.425 per share, paid on April 1, 2020. The increase marks the 20th consecutive year that the Company has increased its dividend.
    - Subsequent to quarter end, the Company declared a quarterly dividend of $0.425 per share, payable on July 1, 2020.

Marketing Strengths

- Canadian Natural has many strengths when marketing its products that will benefit the Company going forward, these include:
    - Balanced and diverse product mix of natural gas, conventional heavy crude oil, conventional light crude oil, thermal in situ and SCO.
    - The Company's natural gas portfolio is robust with approximately 1.4 Bcf/d of economic production exposed to an improving natural gas market, supported by owned and controlled infrastructure and low operating costs. Canadian Natural's natural gas volumes provide significant supportive operating cash flow, targeted at approximately $700 million over the next twelve months at AECO pricing of $2.50/GJ.
    - Canadian Natural has approximately 3.6 million barrels of crude oil storage at major hubs in Edmonton and Hardisty, which allows the Company to adjust monthly sales, manage pipeline logistical constraints, and production fluctuations, as well as pricing differences from month to month.
    - Market egress continues to improve in the mid-term as the Trans Mountain Expansion and Keystone XL projects are progressing with construction, on which Canadian Natural has 94,000 bbl/d and 200,000 bbl/d of committed capacity respectively. Combining these two pipeline projects and including Enbridge Line 3 replacement, Western Canadian egress is targeted to increase by approximately 1.8 MMbbl/d in the mid-term.

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net (loss) earnings	**$ (1,282)**	$ 597	$ 961
Per common share – basic	**$ (1.08)**	$ 0.50	$ 0.80
– diluted	**$ (1.08)**	$ 0.50	$ 0.80
Adjusted net (loss) earnings from operations (1)	**$ (295)**	$ 686	$ 838
Per common share – basic	**$ (0.25)**	$ 0.58	$ 0.70
– diluted	**$ (0.25)**	$ 0.58	$ 0.70
Cash flows from operating activities	**$ 1,725**	$ 2,454	$ 996
Adjusted funds flow (2)	**$ 1,337**	$ 2,494	$ 2,240
Per common share – basic	**$ 1.13**	$ 2.11	$ 1.87
– diluted	**$ 1.13**	$ 2.10	$ 1.86
Cash flows used in investing activities	**$ 859**	$ 854	$ 1,029
Net capital expenditures (3)	**$ 838**	$ 1,056	$ 977
Daily production, before royalties			
Natural gas (MMcf/d)	**1,440**	1,455	1,510
Crude oil and NGLs (bbl/d)	**938,676**	913,782	783,512
Equivalent production (BOE/d) (4)	**1,178,752**	1,156,276	1,035,212

(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 "Advisory" section of this press release.

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

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

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

- A net loss of $1,282 million was realized in Q1/20, while the adjusted net loss in Q1/20 was $295 million.
- Cash flows from operating activities were $1,725 million in Q1/20.
- Canadian Natural generated quarterly adjusted funds flow of $1,337 million in Q1/20, which was negatively impacted by charges taken in the first quarter of approximately $100 million including the impact of approximately $50 million of product inventory valuation adjustments and an additional $50 million related to certain pricing mechanisms impacting realized pricing in the North Sea. The decrease of $1,157 million from Q4/19 levels was also due to lower netbacks across all segments driven largely by lower crude oil and natural gas pricing, partially offset by increased higher value Oil Sands Mining and Upgrading production volumes.
  - Adjusted funds flow was in excess of the Company's net capital expenditures of $838 million and dividend requirements of $444 million in Q1/20, resulting in free cash flow generation of $55 million reflecting the strength of the Company's long life low decline asset base and its effective and efficient operations.
- Cash flows used in investing activities were $859 million in Q1/20.
- Despite low commodity prices at March 31, 2020, upon review of the Company's stated book value of property, plant and equipment no impairment charge was required, reflecting the strength of the asset base.

- Canadian Natural maintained a strong financial position in Q1/20 with significant liquidity of approximately $5.0 billion including cash balances of approximately $1.1 billion and committed and demand bank credit facilities as at March 31, 2020.
- Returns to shareholders totaled $715 million in Q1/20, $444 million by way of dividends and $271 million by way of share repurchases. As previously announced on March 18, 2020, share repurchases have been suspended and the Board of Directors have at the present time made the decision to not renew the Company's NCIB program, which expires in May 2020.
- The Company effectively executed on its curtailment optimization strategy, producing our maximum allowable volumes under the Government of Alberta curtailment program, achieving record quarterly production volumes of 1,178,752 BOE/d in Q1/20, increases of 14% and 2% from Q1/19 and Q4/19 levels respectively.
- Record liquids production was achieved by the Company in Q1/20 with volumes reaching 938,676 bbl/d, increases of 20% and 3% from Q1/19 and Q4/19 levels respectively. The increases from previous periods for BOE's and liquids primarily reflect the following:
  - Increased production from the acquisition of thermal in situ and primary heavy crude oil assets from Devon Canada when compared to Q1/19 levels.
  - Increased production from high utilization rates and reliable operations in Oil Sands Mining and Upgrading following a strong ramp up at Horizon after the successful completion of the turnaround in Q4/19 and the completion of the proactive piping replacement in January 2020, when compared to Q4/19 levels.
  - Record production volumes were optimized across the asset base to achieve maximum allowable production under the mandatory Government of Alberta curtailment guidelines during Q1/20.
  - Higher value SCO was maximized in Q1/20 with conventional crude oil and thermal in situ being curtailed as a result of mandatory Government of Alberta curtailments.
    - The Company's product mix was enhanced in Q1/20 as light crude oil and SCO represented approximately 48% of total corporate production volumes, a 12% increase from Q4/19 levels.
- Canadian Natural's continued focus on delivering effective and efficient operations and cost control was demonstrated as the Company's liquids E&P Q1/20 operating costs were $13.71/bbl (US$10.19/bbl), a 15% reduction from Q1/19 levels.
- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ, was slightly curtailed in Q1/20 averaging 228,574 bbl/d, comparable to Q1/19 and an 8% decrease from Q4/19 levels. The decrease from Q4/19 levels primarily reflects optimizing curtailment volumes across the asset base that resulted in increased production volumes of higher value SCO.
- At the Company's world class Oil Sands Mining and Upgrading assets quarterly production volumes were strong, averaging 438,101 bbl/d of SCO in Q1/20. Increases of 5% and 22% of high value SCO production over Q1/19 and Q4/19 levels respectively, were due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in Q4/19 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of curtailment volumes across the Company's asset base.
  - Industry leading operating costs averaged $20.76/bbl (US$15.43/bbl) of SCO in Q1/20, representing decreases of 3% and 17% from Q1/19 and Q4/19 levels respectively. The decreases in operating costs in Q1/20 from the comparable periods primarily reflects higher utilization rates following a strong ramp up at Horizon after the successful completion of the turnaround in Q4/19 and the proactive piping replacement in January 2020.
    - Oil Sands Mining and Upgrading achieved operating costs of $809 million in Q1/20, a 5% decrease from $856 million in Q4/19. The decrease in operating costs on a total and per barrel basis demonstrated the Company's continued focus on efficiencies and cost control.
    - The Company's Oil Sands Mining and Upgrading operations are top tier, resulting in industry leading operating costs. Canadian Natural's teams continue to focus on efficiencies, innovation and cost control resulting in targeted operating costs to be reduced further.
  - In March 2020, Oil Sands Mining and Upgrading achieved record production of approximately 478,300 bbl/d of SCO as a result of high utilization and safe, steady and reliable operations. Additionally, these strong operations resulted in low operating costs of approximately $18.42/bbl (US$13.20/bbl) of SCO in the month.
    - Additionally, Horizon achieved a significant milestone in March 2020, producing its 500 millionth barrel of cumulative SCO.

- Thermal in situ oil sands production volumes were strong in Q1/20. Including curtailed volumes, production in this segment averaged 228,303 bbl/d, a 142% increase over Q1/19 levels, primarily as a result of the Jackfish acquisition and increased production from Kirby North and pad additions at Primrose. Production decreased by 12% from Q4/19 levels primarily reflecting the optimization of curtailment volumes across the Company's asset base that resulted in increased production volumes of higher value SCO and planned turnaround activities in Q1/20 at Jackfish, which was successfully completed in mid-April 2020.
  - Thermal in situ operating costs were strong in Q1/20 averaging $11.02/bbl (US$8.19/bbl), a decrease of 39% from Q1/19 levels, primarily as a result of higher production volumes, synergies captured to date from the Devon Canada asset acquisition and the Company's continued focus on cost control and lower energy costs.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

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

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

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

Drilling Activity

	Three Months Ended Mar 31			
	2020		2019	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**37**	**35**	30	30
Natural gas	**12**	**11**	10	8
Dry	**—**	**—**	1	1
Subtotal	**49**	**46**	41	39
Stratigraphic test / service wells	**420**	**367**	375	332
Total	**469**	**413**	416	371
Success rate (excluding stratigraphic test / service wells)		**100%**		97%

- The Company's total crude oil and natural gas drilling program of 46 net wells for the three months ended March 31, 2020, excluding strat/service wells, represents an increase of 7 net wells from the same period in 2019.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs production (bbl/d)	**228,574**	247,184	225,291
Net wells targeting crude oil	**28**	9	28
Net successful wells drilled	**28**	9	28
Success rate	**100%**	100%	100%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ, was slightly curtailed in Q1/20 averaging 228,574 bbl/d, comparable to Q1/19 and an 8% decrease from Q4/19 levels. The decrease from Q4/19 levels primarily reflects optimizing curtailment volumes across the asset base that resulted in increased production volumes of higher value SCO.

- Primary heavy crude oil production was curtailed in Q1/20, averaging 82,122 bbl/d, a 20% increase from Q1/19 levels and a decrease of 13% from Q4/19 levels. The decrease from Q4/19 was mainly as a result of the execution of the Company's curtailment optimization strategy and temporary shut-ins and deferral of well servicing given current market conditions. The increase from Q1/19 was as a result of additional volumes from the Devon Canada asset acquisition.
    - Operating costs of $18.68/bbl (US$13.89/bbl) were realized in the Company's primary heavy crude oil operations in Q1/20, an increase of 8% from Q1/19 levels.
- Pelican Lake production averaged 57,986 bbl/d in Q1/20, a 5% decrease from Q1/19 levels and comparable to Q4/19 levels, strong results that reflect the low annual decline of this long life asset.
    - At Pelican Lake, the Company continues to demonstrate effective and efficient operations as Q1/20 operating costs decreased by 8% from Q1/19 levels, averaging $6.18/bbl (US$4.59/bbl) in the quarter, primarily as a result of the Company's focus on cost control.
- North American light crude oil and NGL production averaged 88,466 bbl/d in Q1/20, 7% and 6% decreases from Q1/19 and Q4/19 levels respectively, primarily as a result of the Company's strategic decision to defer planned activities in response to current market conditions combined with the execution of the Company's curtailment optimization strategy.
    - In Q1/20, operating costs were $15.99/bbl (US$11.89/bbl) in the Company's North America light crude oil and NGL areas, comparable with Q1/19 levels, strong results given lower production.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Bitumen production (bbl/d)	**228,303**	259,387	94,146
Net wells targeting bitumen	**6**	3	—
Net successful wells drilled	**6**	3	—
Success rate	**100%**	100%	—%

- Thermal in situ oil sands production volumes were strong in Q1/20. Including curtailed volumes, production in this segment averaged 228,303 bbl/d, a 142% increase over Q1/19 levels, primarily as a result of the Jackfish acquisition and increased production from Kirby North and pad additions at Primrose. Production decreased by 12% from Q4/19 levels primarily reflecting the optimization of curtailment volumes across the Company's asset base that resulted in increased production volumes of higher value SCO and planned turnaround activities in Q1/20 at Jackfish, which was successfully completed in mid-April 2020.
    - Thermal in situ operating costs were strong in Q1/20 averaging $11.02/bbl (US$8.19/bbl), a decrease of 39% from Q1/19 levels, primarily as a result of higher production volumes, synergies captured to date from the Devon Canada asset acquisition and the Company's continued focus on cost control and lower energy costs.

North America Natural Gas

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Natural gas production (MMcf/d)	**1,407**	1,411	1,454
Net wells targeting natural gas	**11**	4	9
Net successful wells drilled	**11**	4	8
Success rate	**100%**	100%	89%

- North America natural gas production was 1,407 MMcf/d in Q1/20, a decrease of 3% from Q1/19 levels and comparable to Q4/19 levels, reflecting strong base production, high reliability and minimal declines given the strategic reduction of capital allocated to natural gas activities.

- North America natural gas operating costs were strong in Q1/20, a decrease of 5% from Q1/19 levels to $1.24/Mcf. These results demonstrate the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control and executing on efficiencies across the entire asset base.
  - At the Company's high value Septimus Montney liquids rich area, operating costs were strong in Q1/20, a 17% decrease from Q1/19 levels, averaging $0.30/Mcfe.
- Canadian Natural's natural gas portfolio is significant, providing the Company with additional production flexibility and opportunities to maximize value as prices improve. The Company has identified a number of highly economic opportunities to add additional natural gas volumes at less than $3,000 per flowing BOE. These activities are targeted to add approximately 60 MMcf/d of natural gas volumes, which equates to approximately 35 MMcf/d for 2020 annual natural gas production levels.
  - Canadian Natural's natural gas volumes provide significant supportive operating cash flow, targeted at approximately $700 million over the next twelve months at AECO pricing of $2.50/GJ.
- In 2020, Canadian Natural targets to use the equivalent of approximately 47% of corporate annual natural gas production within its operations, providing a natural hedge from Western Canadian natural gas prices. Approximately 40% is targeted to be exported to other North American markets and sold internationally, while the remaining 13% is targeted to be exposed to AECO/Station 2 pricing.

International Exploration and Production

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil production (bbl/d)			
North Sea	**27,755**	30,860	25,714
Offshore Africa	**15,943**	18,495	22,155
Natural gas production (MMcf/d)			
North Sea	**23**	25	28
Offshore Africa	**10**	19	28
Net wells targeting crude oil	**1.0**	—	1.6
Net successful wells drilled	**1.0**	—	1.6
Success rate	**100%**	—%	100%

- International E&P crude oil production volumes averaged 43,698 bbl/d in Q1/20, decreases of 9% and 11% from Q1/19 and Q4/19 levels respectively. The decreases were primarily due to natural field declines, planned turnaround activities at Espoir partially offset by strong performance from the 2019 drilling program in the North Sea and at Baobab.
  - In the North Sea, crude oil production volumes of 27,755 bbl/d were achieved in Q1/20, an 8% increase over Q1/19 levels and a 10% decrease from Q4/19 levels. The increase from Q1/19 primarily reflected the impact of added production from the 2019 drilling program, partially offset by natural field declines. The decrease from Q4/19 primarily reflects natural field declines.
    - Q1/20 operating costs in the North Sea decreased by 25% and 12% from Q1/19 and Q4/19 levels respectively, averaging $29.73/bbl. The decreases from the comparable periods primarily reflect reduced maintenance activities in Q1/20 due to COVID-19. The decrease from Q1/19 also reflects the impact of higher production volumes in Q1/20.
  - Offshore Africa crude oil production volumes in Q1/20 averaged 15,943 bbl/d, decreases of 28% and 14% from Q1/19 and Q4/19 levels respectively. The decrease in production from the comparable periods primarily reflects planned turnaround activities at Espoir and natural field declines.
    - Offshore Africa crude oil operating costs averaged $11.88/bbl (US$8.83/bbl) in Q1/20, an increase of 21% from Q1/19 and a decrease of 29% from Q4/19 levels. The increase from Q1/19 was primarily due to decreased production volumes and natural field declines. The decrease from Q4/19 was primarily due to the timing of

liftings from various fields that have different cost structures, partially offset by lower production volumes in Q1/20.

◦ Following the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural has a 20% working interest, preparation is in progress by the operator for the 2020 drilling program including contingency plans to manage COVID-19 related disruption.

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Synthetic crude oil production (bbl/d) (1) (2)	**438,101**	357,856	416,206

(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 quarterly production volumes were strong, averaging 438,101 bbl/d of SCO in Q1/20. Increases of 5% and 22% of high value SCO production over Q1/19 and Q4/19 levels respectively, were due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in Q4/19 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of curtailment volumes across the asset base.
  - Industry leading operating costs averaged $20.76/bbl (US$15.43/bbl) of SCO in Q1/20, representing decreases of 3% and 17% from Q1/19 and Q4/19 levels respectively. The decreases in operating costs in Q1/20 from the comparable periods primarily reflects higher utilization rates following a strong ramp up at Horizon after the successful completion of the turnaround in Q4/19 and the proactive piping replacement in January 2020.
    - Oil Sands Mining and Upgrading achieved operating costs of $809 million in Q1/20, a 5% decrease from $856 million in Q4/19. The decrease in operating costs on a total and per barrel basis demonstrated the Company's continued focus on efficiencies and cost control.
    - The Company's Oil Sands Mining and Upgrading operations are top tier, resulting in industry leading operating costs. Canadian Natural's teams continue to focus on efficiencies, innovation and cost control targeting further operating costs reductions throughout 2020.
  - In March 2020, Oil Sands Mining and Upgrading achieved record production of approximately 478,300 bbl/d of SCO as a result of high utilization, safe, steady and reliable operations. Additionally, these strong operations resulted in low operating costs of approximately $18.42/bbl (US$13.20/bbl) of SCO in the month.
    - Additionally, Horizon achieved a significant milestone in March 2020, producing its 500 millionth barrel of cumulative SCO.
    - Canadian Natural has planned routine de-coking activities at Horizon that were deferred from Q1/20 to May 2020 which will result in Horizon volumes being 50,000 bbl/d lower than normal in the month, running at restricted rates.
  - In the second half of 2020, the Company is targeting planned turnaround activities at both AOSP and Horizon mines. The Company has the flexibility to shift timelines to ensure minimal, if any overlapping activities between the two sites, maximizing high value SCO production and operating cash flows. Details are as follows:
    - At the non-operated Scotford Upgrader, a turnaround is targeted for early in Q3/20, at which time the plant will run at restricted rates. Timing of these activities at the AOSP mines are aligned with the planned turnaround at the Scotford Upgrader. During the turnaround, production from AOSP is targeted to average approximately 100,000 bbl/d net lower than normal, in the months of July 2020 and August 2020.
    - At Horizon, the planned turnaround is targeted for the second half of 2020. Monthly average production is targeted to be impacted by approximately 80,000 bbl/d over a two month period once timing is finalized.

MARKETING

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs pricing			
WTI benchmark price (US$/bbl) (1)	**$ 46.08**	$ 56.96	$ 54.90
WCS heavy differential as a percentage of WTI (%) (2)	**44%**	28%	23%
SCO price (US$/bbl)	**$ 43.39**	$ 56.32	$ 52.19
Condensate benchmark pricing (US$/bbl)	**$ 45.54**	$ 52.99	$ 50.49
Average realized pricing before risk management (C$/bbl) (3)	**$ 25.90**	$ 49.60	$ 53.98
Natural gas pricing			
AECO benchmark price (C$/GJ)	**$ 2.03**	$ 2.21	$ 1.84
Average realized pricing before risk management (C$/Mcf)	**$ 2.22**	$ 2.64	$ 3.09

(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.

- Canadian Natural has approximately 3.6 million barrels of crude oil storage at major hubs in Edmonton and Hardisty, which allows the Company to adjust monthly sales, manage pipeline logistical constraints, and production fluctuations, as well as pricing differences from month to month.
- Market egress continues to improve in the mid-term as the Trans Mountain Expansion and Keystone XL projects are progressing with construction, on which Canadian Natural has 94,000 bbl/d and 200,000 bbl/d of committed capacity respectively. Combining these two pipeline projects and including Enbridge Line 3 replacement, Western Canadian egress is targeted to increase by approximately 1.8 MMbbl/d in the mid-term.
- Base Keystone export pipeline optimization expansion of approximately 50,000 bbl/d was recently announced. In Q3/19, Canadian Natural committed to approximately 10,000 bbl/d of the expansion, which is targeted to be available in 2020.

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 of 1,178,752 BOE/d in Q1/20, with approximately 98% of total production located in G7 countries.
- Canadian Natural generated quarterly adjusted funds flow of $1,337 million in Q1/20, which was negatively impacted by charges taken in the first quarter of approximately $100 million including the impact of approximately $50 million of product inventory valuation adjustments and an additional $50 million related to certain pricing mechanisms impacting realized pricing in the North Sea.
  - Adjusted funds flow was in excess of the Company's net capital expenditures of $838 million and dividend requirements of $444 million in Q1/20, resulting in free cash flow generation of $55 million reflecting the strength of the Company's long life low decline asset base and its effective and efficient operations.
- Returns to shareholders totaled $715 million in Q1/20, $444 million by way of dividends and $271 million by way of share repurchases. As previously announced on March 18, 2020 share repurchases have been suspended and the Board of Directors have at the present time made the decision to not renew the Company's NCIB program, which expires in May 2020.
  - Share repurchases for cancellation from January 1, 2020 and March 10, 2020 totaled 6,970,000 common shares at a weighted average share price of $38.84.

- Canadian Natural is confident that it can maintain a strong overall financial position and strong liquidity, while the Company manages effectively through the current short term commodity price environment. As at March 31, 2020, the Company had approximately $5.0 billion of liquidity available, an increase of $116 million over Q4/19 levels. Liquidity is represented by cash and cash equivalents of approximately $1.1 billion and committed and demand bank credit facilities. The liquidity is more than sufficient to retire, when due, any upcoming debt maturities.
  - Debt to book capitalization and debt to adjusted EBITDA remained strong at 39.4% and 2.6x respectively.
  - Subsequent to quarter end, the Company's $750 million non-revolving term credit facility, originally due February 2021 was increased by $250 million to $1,000 million and extended to February 2022, increasing liquidity.
  - In addition to the Company's strong adjusted funds flow, capital flexibility and access to debt capital markets, Canadian Natural has additional financial levers at its disposal to effectively manage its liquidity. The current approximate value of these financial levers includes third party equity investments of $300 million and cross currency swaps with a total value of $360 million.
- Canadian Natural continues to maintain strong investment credit ratings. The Company has a high degree of communication with credit rating agencies to ensure they understand the robust and sustainable nature of the Company's assets. Their understanding is evident in the following results:
  - On March 20, 2020, Moody’s Investors Service, Inc. (“Moody’s”) affirmed the Company's long term and short term investment grade credit ratings of Baa2 and P-2 with a stable outlook.
  - On March 26, 2020, Standard & Poor’s Rating Services (“S&P”) rating action on the Company resulted in long term and short term investment grade credit ratings of BBB and A-2 with a stable outlook.
  - DBRS Limited (“DBRS”) current credit rating for the Company is BBB high.
- Canadian Natural’s business is unique, robust and sustainable. The strength of the Company's assets and its ability to generate significant and sustainable free cash flow over the long term combined with strong liquidity, production flexibility, significant capital reductions and targeted operating costs savings provided the Board of Directors with the confidence that the Company’s current dividend levels can be sustained through the commodity price cycle.
  - On March 5, 2020, the Company declared a quarterly dividend increase of 13% to $0.425 per share, paid on April 1, 2020. The increase marks the 20th consecutive year that the Company has increased its dividend, reflecting the Board of Directors' confidence in Canadian Natural's strength and robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.425 per share, payable on July 1, 2020.

ADVISORY

Special Note Regarding non-GAAP Financial Measures

This press release includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow; 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 the Company's 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 the Company's 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 the Company's MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the “Liquidity and Capital Resources” section of the Company's MD&A.

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

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

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

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

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

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

Available liquidity is a non-GAAP measure that is derived as cash and cash equivalents, total bank and term credit facilities, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 10 - Long-term Debt in the Company’s consolidated financial statements.

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", "aspiration" 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, without limitation, those in relation to the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), Primrose thermal projects, the Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project, the timing and future operations of the North West Redwater bitumen upgrader and refinery, construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs") or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market, and the development and deployment of technology and technological innovations also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts, and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

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

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak only as of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of effects of the novel coronavirus ("COVID-19") pandemic and the actions of the Organization of the Petroleum Exporting Countries ("OPEC") and non-OPEC countries) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil and natural gas and NGLs prices, including due to actions of OPEC and non-OPEC countries taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company's and its subsidiaries' ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's and its subsidiaries' success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies and assets; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; actions by governmental authorities (including production curtailments mandated by the Government of Alberta); government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of climate change initiatives on capital expenditures and production expenses); asset retirement obligations; the adequacy of the Company's provision for taxes; and other circumstances affecting revenues and expenses.

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

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

Special Note Regarding non-GAAP Financial Measures

This MD&A includes references to financial measures commonly used in the crude oil and natural gas industry, such as: adjusted net earnings (loss) from operations; adjusted funds flow; 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, 2020 and the MD&A and the audited consolidated financial statements of the Company for the year ended December 31, 2019. 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, 2020 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 are discussed in the "Changes in Accounting Policies" section of this MD&A.

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, 2020 in relation to the first quarter of 2019 and the fourth quarter of 2019. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2019, is available on SEDAR at www.sedar.com, and on EDGAR at www.sec.gov. Detailed guidance on production levels, capital expenditures and production expenses can be found on the Company's website at www.cnrl.com. Information on the Company's website, including such guidance, does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated May 6, 2020.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Product sales [1]	**$ 4,652**	$ 6,335	$ 5,541
Crude oil and NGLs	**$ 4,312**	$ 5,947	$ 5,082
Natural gas	**$ 335**	$ 382	$ 456
Net earnings (loss)	**$ (1,282)**	$ 597	$ 961
Per common share – basic	**$ (1.08)**	$ 0.50	$ 0.80
– diluted	**$ (1.08)**	$ 0.50	$ 0.80
Adjusted net earnings (loss) from operations [2]	**$ (295)**	$ 686	$ 838
Per common share – basic	**$ (0.25)**	$ 0.58	$ 0.70
– diluted	**$ (0.25)**	$ 0.58	$ 0.70
Cash flows from operating activities	**$ 1,725**	$ 2,454	$ 996
Adjusted funds flow [3]	**$ 1,337**	$ 2,494	$ 2,240
Per common share – basic	**$ 1.13**	$ 2.11	$ 1.87
– diluted	**$ 1.13**	$ 2.10	$ 1.86
Cash flows used in investing activities	**$ 859**	$ 854	$ 1,029
Net capital expenditures [4]	**$ 838**	$ 1,056	$ 977

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2020 are disclosed in note 19 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 is a non-GAAP measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from Operating Activities" is presented in this MD&A. Adjusted funds flow may not be comparable to similar measures presented by other companies.

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

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

($ millions)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net earnings (loss)	***$ (1,282)***	*$ 597*	*$ 961*
Share-based compensation, net of tax (1)	***(221)***	*148*	*62*
Unrealized risk management (gain) loss, net of tax (2)	***(15)***	*16*	*13*
Unrealized foreign exchange loss (gain), net of tax (3)	***1,121***	*(225)*	*(233)*
Realized foreign exchange gain on settlement of cross currency swaps (4)	***(166)***	*—*	*—*
Loss from investments, net of tax (5) (6)	***268***	*150*	*35*
Adjusted net earnings (loss) from operations	***$ (295)***	*$ 686*	*$ 838*

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plans. The Company's employee stock option plan provides for a cash payment option. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. Accordingly, the fair value of the outstanding vested options is recorded as a liability on the Company's balance sheets and periodic changes in the fair value are recognized in net earnings (loss) or are charged to (recovered from) the Oil Sands Mining and Upgrading segment.

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

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

(4) During the first quarter of 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement.

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

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

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

($ millions)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Cash flows from operating activities	***$ 1,725***	*$ 2,454*	*$ 996*
Net change in non-cash working capital	***(595)***	*(52)*	*1,016*
Abandonment expenditures (1)	***89***	*84*	*108*
Other (2)	***118***	*8*	*120*
Adjusted funds flow	***$ 1,337***	*$ 2,494*	*$ 2,240*

(1) 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.

(2) 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

The net loss for the first quarter of 2020 was $1,282 million compared with net earnings of $961 million for the first quarter of 2019 and net earnings of $597 million for the fourth quarter of 2019. The net loss for the first quarter of 2020 included net after-tax expenses of $987 million compared with net after-tax income of $123 million for the first quarter of 2019 and net after-tax expenses of $89 million for the fourth quarter of 2019 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, foreign exchange gain on the settlement of the cross currency swaps, and loss from investments. Excluding these items, the adjusted net loss from operations for the first quarter of 2020 was $295 million compared with adjusted net earnings from operations of $838 million for the first quarter of 2019 and an adjusted net earnings from operations of $686 million for the fourth quarter of 2019.

The net loss and adjusted net loss from operations for the first quarter of 2020 compared with net earnings and adjusted net earnings from operations for the first quarter of 2019 and the fourth quarter of 2019 primarily reflected:

- lower crude oil and NGLs and natural gas netbacks in the Exploration and Production segments; and
- lower realized SCO prices in the Oil Sands Mining and Upgrading segment.

The impacts of share-based compensation, risk management activities and the impact of fluctuations in foreign exchange rates on long-term debt outstanding at period end 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 2020 were $1,725 million compared with $996 million for the first quarter of 2019 and $2,454 million for the fourth quarter of 2019. 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 2020 was $1,337 million compared with $2,240 million for the first quarter of 2019 and $2,494 million for the fourth quarter of 2019. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures and movements in other long-term assets, including the unamortized cost of the share bonus program and prepaid cost of service tolls.

Production Volumes

Total production before royalties for the first quarter of 2020 increased 14% to 1,178,752 BOE/d from 1,035,212 BOE/d for the first quarter of 2019 and was comparable with 1,156,276 BOE/d for the fourth quarter of 2019. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)	**Mar 31 2020**	Dec 31 2019	Sep 30 2019	Jun 30 2019
Product sales [1]	**$ 4,652**	$ 6,335	$ 6,587	$ 5,931
Crude oil and NGLs	**$ 4,312**	$ 5,947	$ 6,324	$ 5,597
Natural gas	**$ 335**	$ 382	$ 257	$ 324
Net earnings (loss)	**$ (1,282)**	$ 597	$ 1,027	$ 2,831
Net earnings (loss) per common share				
– basic	**$ (1.08)**	$ 0.50	$ 0.87	$ 2.37
– diluted	**$ (1.08)**	$ 0.50	$ 0.87	$ 2.36

($ 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

(1) Further details related to product sales, including 'Other' income, for the three months ended March 31, 2020 are disclosed in note 19 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 OPEC and its impact on world supply, the impact of geopolitical and market uncertainties, including those due to COVID-19 and in connection with governmental responses to COVID-19, on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the Western Canadian Select ("WCS") Heavy Differential from the West Texas Intermediate reference location at Cushing, Oklahoma ("WTI") in North America including the impact of a shortage of takeaway capacity out of the Western Canadian Sedimentary Basin (the "Basin"), the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the North Sea and Offshore Africa and the impact of production curtailments mandated by the Government of Alberta that came into effect January 1, 2019.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production due to the cyclic nature of the Company's Primrose thermal projects, production from Kirby South and Kirby North, the results from the Pelican Lake water and polymer flood projects, fluctuations in the Company's drilling program in North America and the International segments, the impact and timing of acquisitions, including the acquisition of assets from Devon Canada Corporation ("Devon") in the second quarter of 2019, 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 and the impact of shut-in production due to lower demand during COVID-19. Sales volumes also reflected fluctuations due to timing of liftings and maintenance activities in the International segments.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's allocation of capital to higher return crude oil projects, natural decline rates, fluctuating capacity at the Pine River processing facility, shut-in production due to third party pipeline restrictions and related pricing impacts, shut-in production due to low commodity prices, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impact of the demand and cost for services, fluctuations in product mix and production volumes, the impact of seasonal costs, the impact of increased carbon tax and energy costs, cost optimizations across all segments, the impact and timing of acquisitions, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, maintenance activities in the International segments, and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Depletion, depreciation and amortization** – Fluctuations due to changes in sales volumes including the impact and timing of acquisitions and dispositions, proved reserves, asset retirement obligations, finding and development costs associated with crude oil and natural gas exploration, estimated future costs to develop the Company's proved undeveloped reserves, fluctuations in International sales volumes subject to higher depletion rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and the impact of the adoption of IFRS 16 on January 1, 2019.
- **Share-based compensation** – Fluctuations due to the measurement of fair market value of the Company's share-based compensation liability.
- **Risk management** – Fluctuations due to the recognition of gains and losses from the mark-to-market and subsequent settlement of the Company's risk management activities.
- **Interest expense** – Fluctuations due to the adoption of IFRS 16 on January 1, 2019, fluctuating long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange rates** – Fluctuations in the Canadian dollar relative to the US dollar, which impact the realized price the Company receives for its crude oil and natural gas sales, as sales prices are based predominantly on US dollar denominated benchmarks. Fluctuations in realized and unrealized foreign exchange gains and losses were also recorded with respect to US dollar denominated debt, partially offset by the impact of cross currency swap hedges.
- **Gains on acquisition, disposition and revaluation of properties and gains/losses on investments** – Fluctuations due to the recognition of the acquisition, disposition and revaluation of properties in the various periods, fair value changes in the investments in PrairieSky and Inter Pipeline shares, and the equity loss on the Company's interest in the Redwater Partnership.
- **Income tax expense** – Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices decreased significantly in the first quarter of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. Additionally, global crude oil pricing has been impacted by OPEC and Russia increasing crude oil supply into the market. These conditions have had a corresponding impact on the realized prices the Company received for its crude oil and NGLs products in the first quarter of 2020. Subsequent to quarter end, in April 2020, WTI benchmark pricing averaged US$16.70 per bbl and the WCS Heavy Differential averaged US$13.20 per bbl.

Production Flexibility and Cost Control

The Company continues to be nimble and has acted decisively to make appropriate operational improvements to increase efficiencies and cost control and mitigate the impact of the decline in commodity pricing across all of its operations. To mitigate the impact of realized pricing on certain crude oil products, the Company has optimized the production profile across its diverse asset base in the current business environment. The Company has also implemented changes to its compensation program in light of current commodity volatility, and these changes are expected to have an immediate impact on the Company's costs in the second quarter of 2020. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

During periods of low commodity pricing, the Company's focus shifts to optimization of its significant long life low decline assets, including the Oil Sands Mining and Upgrading assets that have a reserve life in excess of 43 years. Low decline assets, including high value SCO, comprise 77% of forecasted 2020 liquids production and will continue to be a key focus of the Company at current commodity price levels.

Production costs in the first quarter of 2020 also reflected the impact of measures to promote social distancing related to COVID-19 at the Oil Sands Mining and Upgrading sites, Offshore platforms in the International segment and the Jackfish and Wolf Lake sites in the North America Exploration and Production segment. The Company continues to mitigate the impact of these costs through its focus on cost control and efficiencies across the asset base.

Liquidity

As at March 31, 2020, the Company had in place revolving bank credit facilities of $4,959 million, of which $3,921 million was available. Including cash and cash equivalents and other liquidity, the Company had approximately $5,000 million in available liquidity. Subsequent to quarter end, the Company's $750 million non-revolving term credit facility, originally due February 2021, was increased by $250 million to $1,000 million and extended to February 2022.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure.

Capital Spending

Effective and efficient operations will continue to be a focus of the Company. The Company's 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million. In March 2020, as a result of the volatility in crude oil pricing, the Company reduced its 2020 capital spending budget to approximately $2,960 million. Subsequent to quarter end, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

Risks and Uncertainties

COVID-19 continues to have the potential to further disrupt the Company’s operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of manpower resulting from quarantines that affect the Company’s labour pools in their local communities, workforce camps or operating sites or that are instituted by local health authorities as a precautionary measure, any of which may require the Company to temporarily reduce or shutdown its operations depending on their extent and severity.

Benchmark Commodity Prices

	Three Months Ended		
(Average for the period)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
WTI benchmark price (US$/bbl)	**$ 46.08**	$ 56.96	$ 54.90
Dated Brent benchmark price (US$/bbl)	**$ 50.42**	$ 62.64	$ 63.34
WCS Heavy Differential from WTI (US$/bbl)	**$ 20.47**	$ 15.84	$ 12.38
SCO price (US$/bbl)	**$ 43.39**	$ 56.32	$ 52.19
Condensate benchmark price (US$/bbl)	**$ 45.54**	$ 52.99	$ 50.49
Condensate Differential from WTI (US$/bbl)	**$ 0.54**	$ 3.97	$ 4.40
NYMEX benchmark price (US$/MMBtu)	**$ 1.95**	$ 2.50	$ 3.16
AECO benchmark price (C$/GJ)	**$ 2.03**	$ 2.21	$ 1.84
US/Canadian dollar average exchange rate (US$)	**$ 0.7434**	$ 0.7576	$ 0.7522

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

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

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$46.08 per bbl for the first quarter of 2020, a decrease of 16% from US$54.90 per bbl for the first quarter of 2019, and a decrease of 19% from US$56.96 per bbl for the fourth quarter of 2019.

Crude oil sales contracts for the Company's North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$50.42 per bbl for the first quarter of 2020, a decrease of 20% from US$63.34 per bbl for the first quarter of 2019, and a decrease of 20% from US$62.64 per bbl for the fourth quarter of 2019.

The decrease in WTI and Brent pricing for the first quarter of 2020 from the comparable periods primarily reflected significant reductions in refinery utilization due to decreased demand as a result of COVID-19. Additionally, global crude oil pricing has been impacted by OPEC and Russia increasing crude oil supply into the market.

The WCS Heavy Differential averaged US$20.47 per bbl for the first quarter of 2020, an increase of 65% from US$12.38 per bbl for the first quarter of 2019, and an increase of 29% from US$15.84 per bbl for the fourth quarter of 2019. The widening of the WCS Heavy Differential for the first quarter of 2020 from the comparable periods primarily reflected constrained egress capacity.

The SCO price averaged US$43.39 per bbl for the first quarter of 2020, a decrease of 17% from US$52.19 per bbl for the first quarter of 2019, and a decrease of 23% from US$56.32 per bbl for the fourth quarter of 2019. The decrease in SCO pricing for the first quarter of 2020 from the comparable periods primarily reflected a decrease in WTI benchmark pricing.

NYMEX natural gas pricing averaged US$1.95 per MMBtu for the first quarter of 2020, a decrease of 38% from US$3.16 per MMBtu for the first quarter of 2019 and a decrease of 22% from US$2.50 per MMBtu for the fourth quarter of 2019. The decrease in NYMEX natural gas pricing for the first quarter of 2020 from the comparable periods primarily reflected increased production levels in North America and the impact of seasonal weather conditions.

AECO natural gas pricing averaged $2.03 per GJ for the first quarter of 2020, an increase of 10% from $1.84 per GJ for the first quarter of 2019 and a decrease of 8% from $2.21 per GJ for the fourth quarter of 2019. The increase in AECO natural gas pricing for the first quarter of 2020 from the first quarter of 2019 primarily reflected additional egress capability. The decrease in AECO natural gas pricing for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected seasonal demand factors and lower export prices.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**456,877**	506,571	319,437
North America – Oil Sands Mining and Upgrading (1)	**438,101**	357,856	416,206
North Sea	**27,755**	30,860	25,714
Offshore Africa	**15,943**	18,495	22,155
	938,676	913,782	783,512
Natural gas (MMcf/d)			
North America	**1,407**	1,411	1,454
North Sea	**23**	25	28
Offshore Africa	**10**	19	28
	1,440	1,455	1,510
Total barrels of oil equivalent (BOE/d)	**1,178,752**	1,156,276	1,035,212
Product mix			
Light and medium crude oil and NGLs	**11%**	12%	14%
Pelican Lake heavy crude oil	**5%**	5%	6%
Primary heavy crude oil	**7%**	8%	7%
Bitumen (thermal oil)	**20%**	23%	9%
Synthetic crude oil (1)	**37%**	31%	40%
Natural gas	**20%**	21%	24%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)			
Crude oil and NGLs	**92%**	94%	91%
Natural gas	**8%**	6%	9%

(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 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**414,460**	438,894	281,233
North America – Oil Sands Mining and Upgrading	**432,936**	340,262	397,639
North Sea	**27,693**	30,815	25,675
Offshore Africa	**15,296**	17,294	20,260
	890,385	827,265	724,807
Natural gas (MMcf/d)			
North America	**1,374**	1,351	1,399
North Sea	**23**	25	28
Offshore Africa	**10**	18	25
	1,407	1,394	1,452
Total barrels of oil equivalent (BOE/d)	**1,124,839**	1,059,562	966,758

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

Crude oil and NGLs production before royalties for the first quarter of 2020 increased 20% to average a record 938,676 bbl/d from 783,512 bbl/d for the first quarter of 2019, and increased 3% from 913,782 bbl/d for the fourth quarter of 2019. The increase in crude oil and NGLs production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon. The increase in production for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected high utilization rates and reliable operations in Oil Sands Mining and Upgrading following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020, offsetting the impact of mandatory Government of Alberta curtailment by optimizing higher value SCO production volumes. While optimizing production volumes across the asset base, the Company achieved maximum allowable production under the Government of Alberta curtailment guidelines during the first quarter of 2020.

Natural gas production before royalties for the first quarter of 2020 of 1,440 MMcf/d decreased 5% from 1,510 MMcf/d for the first quarter of 2019, and was comparable with 1,455 MMcf/d for the fourth quarter of 2019. The decrease in natural gas production for the first quarter of 2020 from the first quarter of 2019 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the first quarter of 2020 increased 43% to average 456,877 bbl/d from 319,437 bbl/d for the first quarter of 2019, and decreased 10% from 506,571 bbl/d for the fourth quarter of 2019. The increase in crude oil and NGLs production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon. The decrease in production from the fourth quarter of 2019 was primarily due to the Company’s optimization of higher value SCO production during mandatory Government of Alberta curtailment.

Thermal oil production before royalties for the first quarter of 2020 increased 142% to 228,303 bbl/d from 94,146 bbl/d for the first quarter of 2019, and decreased 12% from 259,387 bbl/d for the fourth quarter of 2019. The increase in thermal oil production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of production from the acquisition of thermal and heavy oil assets from Devon, together with new production from Kirby North and pad additions at Primrose. The decrease in thermal oil production from the fourth quarter of 2019 primarily reflected the optimization of curtailment volumes across the Company's asset base that resulted in increased production volumes of higher value SCO, and planned turnaround activities at Jackfish during the first quarter of 2020, which were successfully completed in mid-April 2020.

Pelican Lake heavy crude oil production before royalties decreased 5% to 57,986 bbl/d in the first quarter of 2020 from 61,240 bbl/d in the first quarter of 2019, and was comparable with 59,013 bbl/d in the fourth quarter of 2019, reflecting the field’s low natural decline rate.

Natural gas production before royalties for the first quarter of 2020 decreased 3% to 1,407 MMcf/d from 1,454 MMcf/d for the first quarter of 2019, and was comparable with 1,411 MMcf/d for the fourth quarter of 2019. The decrease in natural gas production for the first quarter of 2020 from the first quarter of 2019 primarily reflected natural field declines, together with the strategic reduction of capital allocated to natural gas activities.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the first quarter of 2020 increased 5% to average 438,101 bbl/d from 416,206 bbl/d for the first quarter of 2019 and increased 22% from 357,856 bbl/d for the fourth quarter of 2019. The increase in SCO production for the first quarter of 2020 from the comparable periods was due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of higher value SCO production during mandatory Government of Alberta curtailment.

North Sea

North Sea crude oil production before royalties for the first quarter of 2020 increased 8% to 27,755 bbl/d from 25,714 bbl/d for the first quarter of 2019 and decreased 10% from 30,860 bbl/d for the fourth quarter of 2019. The increase in production for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of added production from the 2019 drilling program, partially offset by natural field declines. The decrease in production for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the first quarter of 2020 decreased 28% to 15,943 bbl/d from 22,155 bbl/d for the first quarter of 2019 and decreased 14% from 18,495 bbl/d for the fourth quarter of 2019. The decrease in production for the first quarter of 2020 from the comparable periods primarily reflected planned turnaround activities at Espoir and natural field declines.

International Crude Oil Inventory Volumes

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

(bbl)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
North Sea	**—**	344,726	851,919
Offshore Africa	**532,347**	519,504	1,055,383
	532,347	864,230	1,907,302

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) [1]			
Sales price [2]	**$ 25.90**	$ 49.60	$ 53.98
Transportation	**3.87**	3.53	3.26
Realized sales price, net of transportation	**22.03**	46.07	50.72
Royalties	**2.34**	6.03	5.95
Production expense	**13.71**	12.46	16.04
Netback	**$ 5.98**	$ 27.58	$ 28.73
Natural gas ($/Mcf) [1]			
Sales price [2]	**$ 2.22**	$ 2.64	$ 3.09
Transportation	**0.46**	0.43	0.46
Realized sales price, net of transportation	**1.76**	2.21	2.63
Royalties	**0.05**	0.11	0.12
Production expense	**1.31**	1.17	1.33
Netback	**$ 0.40**	$ 0.93	$ 1.18
Barrels of oil equivalent ($/BOE) [1]			
Sales price [2]	**$ 21.90**	$ 39.20	$ 39.27
Transportation	**3.50**	3.24	3.06
Realized sales price, net of transportation	**18.40**	35.96	36.21
Royalties	**1.70**	4.37	3.78
Production expense	**11.87**	10.79	12.68
Netback	**$ 4.83**	$ 20.80	$ 19.75

(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 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1) (2)			
North America	**$ 23.48**	$ 46.06	$ 50.92
North Sea	**$ 45.85**	$ 87.76	$ 87.61
Offshore Africa	**$ 58.16**	$ 70.73	$ 81.00
Average	**$ 25.90**	$ 49.60	$ 53.98
Natural gas ($/Mcf) (1) (2)			
North America	**$ 2.15**	$ 2.52	$ 2.88
North Sea	**$ 3.75**	$ 5.10	$ 10.05
Offshore Africa	**$ 8.94**	$ 8.58	$ 7.34
Average	**$ 2.22**	$ 2.64	$ 3.09
Average ($/BOE) (1) (2)	**$ 21.90**	$ 39.20	$ 39.27

(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 $23.48 per bbl for the first quarter of 2020, a decrease of 54% compared with $50.92 per bbl for the first quarter of 2019 and a decrease of 49% compared with $46.06 per bbl for the fourth quarter of 2019. The decrease in realized crude oil prices for the first quarter of 2020 from the comparable periods was primarily due to lower WTI benchmark pricing together with the widening of the WCS Heavy Differential due to constrained egress capacity. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2020, contributed approximately 137,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 25% to average $2.15 per Mcf for the first quarter of 2020 compared with $2.88 per Mcf for the first quarter of 2019, and decreased 15% compared with $2.52 per Mcf for the fourth quarter of 2019. The decrease in realized natural gas prices for the first quarter of 2020 from the comparable periods primarily reflected increased production levels in North America, seasonal demand factors, and lower export prices.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 38.15**	$ 47.32	$ 49.13
Pelican Lake heavy crude oil ($/bbl)	**$ 27.75**	$ 51.66	$ 56.28
Primary heavy crude oil ($/bbl)	**$ 25.01**	$ 49.72	$ 52.27
Bitumen (thermal oil) ($/bbl)	**$ 16.53**	$ 42.93	$ 48.27
Natural gas ($/Mcf)	**$ 2.15**	$ 2.52	$ 2.88

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

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

North Sea

North Sea realized crude oil prices decreased 48% to average $45.85 per bbl for the first quarter of 2020 from $87.61 per bbl for the first quarter of 2019 and decreased 48% from $87.76 per bbl for the fourth quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing from 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 2020 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices decreased 28% to average $58.16 per bbl for the first quarter of 2020 from $81.00 per bbl for the first quarter of 2019 and decreased 18% from $70.73 per bbl for the fourth quarter of 2019. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the first quarter of 2020 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 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 2.49**	$ 6.52	$ 6.22
North Sea	**$ 0.10**	$ 0.13	$ 0.13
Offshore Africa	**$ 2.36**	$ 4.60	$ 6.93
Average	**$ 2.34**	$ 6.03	$ 5.95
Natural gas ($/Mcf) (1)			
North America	**$ 0.05**	$ 0.11	$ 0.11
Offshore Africa	**$ 0.51**	$ 0.39	$ 0.85
Average	**$ 0.05**	$ 0.11	$ 0.12
Average ($/BOE) (1)	**$ 1.70**	$ 4.37	$ 3.78

(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 2020 and the comparable periods reflected movements in benchmark commodity prices. North America crude oil royalties also reflected fluctuations in the WCS Heavy Differential and changes in the production mix between high and low royalty rate product types.

Crude oil and NGLs royalty rates averaged approximately 11% of product sales for the first quarter of 2020 compared with 12% for the first quarter of 2019 and 14% for the fourth quarter of 2019. The decrease in royalty rates for the first quarter of 2020 from the comparable periods was primarily due to lower benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 2% of product sales for the first quarter of 2020 compared with 4% for the first quarter of 2019 and the fourth quarter of 2019. The decrease in royalty rates for the first quarter of 2020 from the comparable periods was primarily due to lower benchmark pricing.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the first quarter of 2020, compared with 9% of product sales for the first quarter of 2019 and 6% for the fourth quarter of 2019. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2020	Dec 31 2019	Mar 31 2019
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 12.69**	$ 10.74	$ 15.07
North Sea	**$ 29.73**	$ 33.67	$ 39.68
Offshore Africa	**$ 11.88**	$ 16.75	$ 9.79
Average	**$ 13.71**	$ 12.46	$ 16.04
Natural gas ($/Mcf) (1)			
North America	**$ 1.24**	$ 1.11	$ 1.30
North Sea	**$ 3.45**	$ 3.25	$ 2.41
Offshore Africa	**$ 5.56**	$ 3.19	$ 2.12
Average	**$ 1.31**	$ 1.17	$ 1.33
Average ($/BOE) (1)	**$ 11.87**	$ 10.79	$ 12.68

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

North America

North America crude oil and NGLs production expense for the first quarter of 2020 of $12.69 per bbl decreased 16% from $15.07 per bbl for the first quarter of 2019 and increased 18% from $10.74 per bbl for the fourth quarter of 2019. The decrease in production expense per bbl for the first quarter of 2020 from the first quarter of 2019 primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose. The increase in production expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of seasonal conditions, lower sales volumes, and higher energy costs, 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 2020 of $1.24 per Mcf decreased 5% from $1.30 per Mcf for the first quarter of 2019 and increased 12% from $1.11 per Mcf for the fourth quarter of 2019. The decrease in production expense per Mcf for the first quarter of 2020 from the first quarter of 2019 primarily reflected the Company’s continued focus on cost control and increased volumes processed in strategically owned and operated infrastructure. The increase in production expense per Mcf for the first quarter of 2020 from the fourth quarter of 2019 primarily reflected the impact of seasonal conditions and higher energy costs, partially offset by the Company's continuous focus on cost control and achieving efficiencies across the entire asset base.

North Sea

North Sea crude oil production expense for the first quarter of 2020 decreased 25% to $29.73 per bbl from $39.68 per bbl for the first quarter of 2019 and decreased 12% from $33.67 per bbl for the fourth quarter of 2019. The decrease in production expense per bbl for the first quarter of 2020 from the comparable periods primarily reflected reduced maintenance activities due to COVID-19 in the first quarter of 2020. The decrease in production expense per bbl from the first quarter of 2019 also reflected the impact of higher production volumes in the first quarter of 2020. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the first quarter of 2020 increased 21% to $11.88 per bbl from $9.79 per bbl for the first quarter of 2019 and decreased 29% from $16.75 per bbl for the fourth quarter of 2019. The increase in production expense per bbl for the first quarter of 2020 from the first quarter of 2019 was primarily due to decreased production volumes, reflecting natural field declines. The decrease in production expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to the timing of liftings from various fields that have different cost structures, partially offset by lower production volumes in the first quarter of 2020.

Crude oil production expense in Offshore Africa for the first quarter of 2020 and comparable periods also reflected 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 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 1,095**	$ 1,083	$ 843
$/BOE (1)	**$ 15.75**	$ 14.98	$ 15.54

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

Depletion, depreciation and amortization expense for the first quarter of 2020 of $15.75 per BOE was comparable with $15.54 per BOE for the first quarter of 2019 and increased 5% from $14.98 per BOE for the fourth quarter of 2019.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended		
($ millions, except per BOE amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 35**	$ 36	$ 28
$/BOE (1)	**$ 0.50**	$ 0.49	$ 0.54

(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 2020 of $0.50 per BOE decreased 7% from $0.54 per BOE for the first quarter of 2019 and was comparable with $0.49 per BOE for the fourth quarter of 2019. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the sites. Production in the first quarter of 2020 was strong and averaged 438,101 bbl/d due to high utilization rates and reliable operations following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. Production reflected the Company's optimization of higher value SCO production during mandatory Government of Alberta curtailment.

The Company achieved production costs of $809 million for the first quarter of 2020, a 5% decrease from $856 million for the fourth quarter of 2019. The decrease in production costs on a total and per barrel basis demonstrated the Company's continued focus on efficiencies and cost control.

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

	Three Months Ended		
($/bbl) (1)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
SCO realized sales price (2)	**$ 50.88**	$ 68.67	$ 65.86
Bitumen value for royalty purposes (3)	**$ 16.82**	$ 44.88	$ 48.16
Bitumen royalties (4)	**$ 0.87**	$ 3.47	$ 2.31
Transportation	**$ 1.28**	$ 1.33	$ 1.17

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price averaged $50.88 per bbl for the first quarter of 2020, a decrease of 23% from $65.86 per bbl for the first quarter of 2019 and a decrease of 26% from $68.67 per bbl for the fourth quarter of 2019. The decrease in the realized SCO sales price for the first quarter of 2020 from the comparable periods primarily reflected movements in WTI benchmark pricing.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production costs disclosed in note 19 to the Company's unaudited interim consolidated financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Production costs	**$ 809**	$ 856	$ 822
Less: costs incurred during turnaround periods	**—**	(71)	—
Adjusted production costs	**$ 809**	$ 785	$ 822
Adjusted production costs, excluding natural gas costs	**$ 773**	$ 743	$ 779
Natural gas costs	**36**	42	43
Adjusted production costs	**$ 809**	$ 785	$ 822

	Three Months Ended		
($/bbl) (1)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Adjusted production costs, excluding natural gas costs	**$ 19.83**	$ 21.79	$ 20.33
Natural gas costs	**0.93**	1.23	1.13
Adjusted production costs	**$ 20.76**	$ 23.02	$ 21.46
Sales (bbl/d)	**428,515**	370,468	425,790

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

Production costs for the first quarter of 2020 averaged $20.76 per bbl, a decrease of 3% from $21.46 per bbl for the first quarter of 2019 and a decrease of 10% from $23.02 per bbl for the fourth quarter of 2019. The decrease in production costs per bbl for the first quarter of 2020 from the comparable periods primarily reflected higher utilization rates following a strong ramp up at Horizon after the successful completion of the turnaround in the fourth quarter of 2019 and the completion of the proactive piping replacement in January 2020. The Company continued to focus on efficiencies and cost control to proactively mitigate the impact of the decline in commodity pricing.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 440**	$ 464	$ 417
Less: depreciation incurred during turnaround periods	**—**	(46)	—
Adjusted depletion, depreciation and amortization	**$ 440**	$ 418	$ 417
$/bbl (1)	**$ 11.28**	$ 12.25	$ 10.88

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

Depletion, depreciation and amortization expense for the first quarter of 2020 increased 4% to $11.28 per bbl from $10.88 per bbl for the first quarter of 2019 and decreased 8% from $12.25 per bbl for the fourth quarter of 2019. The decrease in depletion, depreciation and amortization expense per bbl for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to the impact of the proactive piping replacement in the fourth quarter of 2019.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended		
($ millions, except per bbl amounts)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Expense	**$ 17**	$ 14	$ 16
$/bbl (1)	**$ 0.44**	$ 0.44	$ 0.41

(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 $0.44 per bbl for the first quarter of 2020 increased 7% from $0.41 per bbl for the first quarter of 2019 and compared with $0.44 per bbl for the fourth quarter of 2019. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Revenue	**$ 21**	$ 26	$ 21
Less:			
Production expense	**6**	5	6
Depreciation	**4**	3	3
Equity loss from investment	**—**	73	60
Segment earnings (loss) before taxes	**$ 11**	$ (55)	$ (48)

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

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

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at March 31, 2020, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $229 million, for a Company total of $668 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at March 31, 2020, the Company had recognized $148 million in prepaid cost of service tolls (December 31, 2019 – $130 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 2021. As at March 31, 2020, Redwater Partnership had borrowings of $2,786 million under the credit facility.

During the fourth quarter of 2019, the carrying value of the Redwater Partnership investment was reduced to $nil. The unrecognized share of losses from the Redwater Partnership for the three months ended March 31, 2020 was $93 million (March 31, 2019 – recognized equity loss of $60 million). As at March 31, 2020, the cumulative unrecognized share of losses from the Redwater Partnership was $152 million (December 31, 2019 – $59 million). The unrecognized share of losses for the three months ended March 31, 2020 primarily reflected the impact of Redwater Partnership deferring cost of service toll revenue until it achieves commercial operations and is reliably processing toll payers' bitumen.

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Expense	**$ 108**	$ 95	$ 70
$/BOE [(1)]	**$ 1.00**	$ 0.90	$ 0.76

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

Administration expense for the first quarter of 2020 of $1.00 per BOE increased 32% from $0.76 per BOE for the first quarter of 2019 and increased 11% from $0.90 per BOE for the fourth quarter of 2019. Administration expense per BOE increased for the first quarter of 2020 from the comparable periods primarily due to the impact of higher personnel costs, including those related to the acquisition of assets from Devon.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
(Recovery) expense	**$ (223)**	$ 161	$ 62

The Company's Stock Option Plan provides current employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The PSU plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met.

The Company recorded a $223 million share-based compensation recovery for the first quarter of 2020, 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 recovery for the first quarter of 2020 was $7 million related to PSUs granted to certain executive employees (March 31, 2019 – $10 million expense). For the first quarter of 2020, the Company charged $1 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (March 31, 2019 – $1 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
Expense, gross	**$ 214**	$ 225	$ 211
Less: capitalized interest	**8**	8	20
Expense, net	**$ 206**	$ 217	$ 191
$/BOE [(1)]	**$ 1.90**	$ 2.04	$ 2.06
Average effective interest rate	**3.9%**	3.9%	4.1%

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

Capitalized interest of $8 million for the first quarter of 2020 was related to residual project activities at Horizon.

Net interest and other financing expense per BOE for the first quarter of 2020 decreased 8% to $1.90 per BOE from $2.06 per BOE for the first quarter of 2019 and decreased 7% from $2.04 per BOE for the fourth quarter of 2019. The decrease in interest expense per BOE for the first quarter of 2020 from the first quarter of 2019 primarily reflected higher sales volumes in the first quarter of 2020.The decrease in interest expense per BOE for the first quarter of 2020 from the fourth quarter of 2019 was primarily due to lower average debt levels.

The Company's average effective interest rate for the first quarter of 2020 decreased from the first quarter of 2019 primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Foreign currency contracts	**$ (57)**	$ 5	$ —
Natural gas financial instruments	**10**	6	(1)
Crude oil and NGLs financial instruments	**—**	—	28
Realized (gain) loss	**(47)**	11	27
Foreign currency contracts	**(9)**	10	9
Natural gas financial instruments	**(8)**	7	—
Crude oil and NGLs financial instruments	**—**	—	5
Unrealized (gain) loss	**(17)**	17	14
Net (gain) loss	**$ (64)**	$ 28	$ 41

During the first quarter of 2020, the net realized risk management gains were related to the settlement of foreign currency contracts. The Company recorded a net unrealized gain of $17 million ($15 million after-tax) on its risk management activities for the first quarter of 2020 (three months ended December 31, 2019 – unrealized loss of $17 million; $16 million after-tax; three months ended March 31, 2019 – unrealized loss of $14 million; $13 million after-tax).

Further details related to outstanding derivative financial instruments at March 31, 2020 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net realized gain	**$ (199)**	$ (4)	$ (6)
Net unrealized loss (gain)	**1,121**	(225)	(233)
Net loss (gain) [1]	**$ 922**	$ (229)	$ (239)

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

The net realized foreign exchange gain for the first quarter of 2020 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling and the settlement of the US$500 million cross currency swaps during the quarter. The net unrealized foreign exchange loss for the first quarter of 2020 was primarily related to the impact of a weaker Canadian dollar with respect to outstanding US dollar debt. The net unrealized loss (gain) for each of the periods presented reflected the impact of the cross currency swaps, including the settlement of US$500 million in cross currency swaps during the first quarter of 2020 (three months ended March 31, 2020 – unrealized loss of $74 million, December 31, 2019 – unrealized loss of $29 million, March 31, 2019 – unrealized loss of $30 million). The US/Canadian dollar exchange rate at March 31, 2020 was US$0.7082 (December 31, 2019 – US$0.7713, March 31, 2019 – US$0.7485).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Mar 31 2020	Dec 31 2019	Mar 31 2019
North America [1]	**$ (194)**	$ (20)	$ 163
North Sea	**9**	40	29
Offshore Africa	**4**	7	12
PRT [2] – North Sea	**—**	—	(42)
Other taxes	**2**	4	3
Current income tax (recovery) expense	**(179)**	31	165
Deferred income tax expense	**20**	194	94
	$ (159)	$ 225	$ 259
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**36%**	26%	26%

(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 and other current income tax.

The effective income tax rate for the first quarter of 2020 and the comparable periods included the impact of non-taxable items in North America and North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea for the first quarter of 2020 and the prior periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022.

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

NET CAPITAL EXPENDITURES [1]

($ millions)	Three Months Ended **Mar 31 2020**	Dec 31 2019	Mar 31 2019
Exploration and Evaluation			
Net property (dispositions) acquisitions	**$ (18)**	$ —	$ 1
Net expenditures	**25**	—	32
Total Exploration and Evaluation	**7**	—	33
Property, Plant and Equipment			
Net property acquisitions	**13**	20	24
Well drilling, completion and equipping	**202**	169	254
Production and related facilities	**214**	238	287
Capitalized interest and other	**12**	15	29
Net expenditures	**441**	442	594
Total Exploration and Production	**448**	442	627
Oil Sands Mining and Upgrading			
Project costs	**56**	121	76
Sustaining capital	**201**	334	140
Turnaround costs	**23**	57	8
Capitalized interest and other	**9**	9	10
Total Oil Sands Mining and Upgrading	**289**	521	234
Midstream and Refining	**1**	1	2
Abandonments [2]	**89**	84	108
Head office	**11**	8	6
Total net capital expenditures	**$ 838**	$ 1,056	$ 977
By segment			
North America	**$ 395**	$ 330	$ 524
North Sea	**26**	63	36
Offshore Africa	**27**	49	67
Oil Sands Mining and Upgrading	**289**	521	234
Midstream and Refining	**1**	1	2
Abandonments [2]	**89**	84	108
Head office	**11**	8	6
Total	**$ 838**	$ 1,056	$ 977

(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) 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 2020**	Dec 31 2019	Mar 31 2019
Cash flows used in investing activities	***$ 859***	*$ 854*	*$ 1,029*
Net change in non-cash working capital	***(110)***	*118*	*(160)*
Abandonment expenditures (1)	***89***	*84*	*108*
Net capital expenditures	***$ 838***	*$ 1,056*	*$ 977*

(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 2020 were $838 million compared with $977 million for the first quarter of 2019 and $1,056 million for the fourth quarter of 2019.

2020 Capital Budget

The Company's 2020 capital budget is flexible and disciplined and was originally targeted, when finalized on December 4, 2019, at approximately $4,050 million. In March 2020, as a result of the volatility in crude oil pricing, the Company reduced its 2020 capital spending budget to approximately $2,960 million. Subsequent to quarter end, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

The Company's ability to be nimble in a changing environment was evident as flexibility was utilized by drilling 10 fewer crude oil and bitumen wells than originally budgeted.

Drilling Activity (1)

	Three Months Ended		
(number of wells)	**Mar 31 2020**	Dec 31 2019	Mar 31 2019
Net successful natural gas wells	**11**	4	8
Net successful crude oil wells (2)	**35**	12	30
Dry wells	**—**	—	1
Stratigraphic test / service wells	**367**	89	332
Total	**413**	105	371
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	97%

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

(2) Includes bitumen wells.

North America

During the first quarter of 2020, the Company targeted 11 net natural gas wells, 6 net primary heavy crude oil wells, 6 net bitumen (thermal oil) wells and 22 net light crude oil wells.

North Sea

During the first quarter of 2020, the Company completed 1 gross light crude oil well (1.0 on a net basis) in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		Mar 31 2020		Dec 31 2019		Mar 31 2019
Working capital (1)	**$**	**683**	$	241	$	319
Long-term debt (2) (3)	**$**	**22,687**	$	20,982	$	20,990
Less: cash and cash equivalents		**1,071**		139		90
Long-term debt, net	**$**	**21,616**	$	20,843	$	20,900
Share capital	**$**	**9,517**	$	9,533	$	9,358
Retained earnings		**23,425**		25,424		22,852
Accumulated other comprehensive income		**320**		34		58
Shareholders' equity	**$**	**33,262**	$	34,991	$	32,268
Debt to book capitalization (3) (4)		**39.4%**		37.3%		39.3%
Debt to market capitalization (3) (5)		**48.7%**		29.5%		32.2%
After-tax return on average common shareholders' equity (6)		**9.4%**		16.1%		9.2%
After-tax return on average capital employed (3) (7)		**6.8%**		10.9%		6.6%

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

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

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

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

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

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

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

As at March 31, 2020, 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 "Business Environment" section of this MD&A and in the "Risks and Uncertainties" section of the Company's annual MD&A for the year ended December 31, 2019. 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;
- 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;
- 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;
- Monitoring the Company's ability to fulfill financial obligations as they become due or ability to monetize assets in a timely manner at a reasonable price;

- 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, 2020, the non-revolving term credit facilities were fully drawn.
  - Subsequent to March 31, 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.
  - 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 the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - In July 2019, the Company filed new base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, expiring in August 2021. 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.

As at March 31, 2020, the Company had in place revolving bank credit facilities of $4,959 million, of which $3,921 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. Including cash and cash equivalents and other liquidity, the Company had approximately $5,000 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

As at March 31, 2020, the Company had total US dollar denominated debt with a carrying amount of $15,994 million (US$11,327 million), before transaction costs and original issue discounts. This included $5,968 million (US$4,227 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$3,677 million). The fixed repayment amount of these hedging instruments is $5,700 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $268 million to $15,726 million as at March 31, 2020.

During the first quarter of 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement.

Net long-term debt was $21,616 million at March 31, 2020, resulting in a debt to book capitalization ratio of 39.4% (December 31, 2019 – 37.3%); 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 are 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, 2020 are discussed in note 10 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, 2020, 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, 2020, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for April 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at March 31, 2020 are discussed in note 17 of the Company's unaudited interim consolidated financial statements.

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

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Long-term debt [1]	$	2,803	$	1,869	$	10,087	$	8,031
Other long-term liabilities [2]	$	250	$	188	$	412	$	971
Interest and other financing expense [3]	$	900	$	829	$	1,849	$	5,071

(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, $221 million; one to less than two years, $163 million; two to less than five years, $391 million; and thereafter, $971 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, 2020.

Share Capital

As at March 31, 2020, there were 1,180,854,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 56,202,000 stock options outstanding. As at May 5, 2020, the Company had 1,180,854,000 common shares outstanding and 55,989,000 stock options outstanding.

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

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

For the three months ended March 31, 2020, the Company purchased for cancellation 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million. Retained earnings were reduced by $215 million, representing the excess of the purchase price of common shares over their average carrying value.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company’s commitments as at March 31, 2020:

		Remaining 2020		2021		2022		2023		2024		Thereafter
Product transportation [1]	$	563	$	733	$	641	$	728	$	701	$	7,911
North West Redwater Partnership service toll [2]	$	113	$	168	$	162	$	160	$	154	$	2,828
Offshore vessels and equipment	$	57	$	70	$	10	$	—	$	—	$	—
Field equipment and power	$	24	$	21	$	20	$	21	$	20	$	249
Other	$	19	$	20	$	17	$	17	$	17	$	29

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

(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 tolls, currently consisting of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,222 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

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS standards. Materiality is used in making judgments related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions and judgements in the application of IFRS that have a significant impact on the financial results of the Company. For the three months ended March 31, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2019.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2020 that have materially affected, or are reasonably likely to materially affect the Company’s ICFR. Based on inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

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INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2020	Dec 31 2019
ASSETS			
Current assets			
Cash and cash equivalents		**$ 1,071**	$ 139
Accounts receivable		**1,281**	2,465
Current income taxes receivable		**243**	13
Inventory	4	**940**	1,152
Prepaids and other		**201**	174
Investments	8	**222**	490
Current portion of other long-term assets	9	**226**	54
		4,184	4,487
Exploration and evaluation assets	5	**2,572**	2,579
Property, plant and equipment	6	**66,341**	68,043
Lease assets	7	**1,717**	1,789
Other long-term assets	9	**1,265**	1,223
		$ 76,079	$ 78,121
LIABILITIES			
Current liabilities			
Accounts payable		**$ 802**	$ 816
Accrued liabilities		**2,214**	2,611
Current portion of long-term debt	10	**2,803**	2,391
Current portion of other long-term liabilities	7,11	**485**	819
		6,304	6,637
Long-term debt	10	**19,884**	18,591
Other long-term liabilities	7,11	**6,024**	7,363
Deferred income taxes		**10,605**	10,539
		42,817	43,130
SHAREHOLDERS' EQUITY			
Share capital	13	**9,517**	9,533
Retained earnings		**23,425**	25,424
Accumulated other comprehensive income	14	**320**	34
		33,262	34,991
		$ 76,079	$ 78,121

Commitments and contingencies (note 18).

Approved by the Board of Directors on May 6, 2020.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2020	Mar 31 2019
Product sales	19	**$ 4,652**	$ 5,541
Less: royalties		**(152)**	(293)
Revenue		**4,500**	5,248
Expenses			
Production		**1,684**	1,530
Transportation, blending and feedstock		**1,432**	1,039
Depletion, depreciation and amortization	6,7	**1,564**	1,263
Administration		**108**	70
Share-based compensation	11	**(223)**	62
Asset retirement obligation accretion	11	**52**	44
Interest and other financing expense		**206**	191
Risk management activities	17	**(64)**	41
Foreign exchange loss (gain)		**922**	(239)
Loss from investments	8,9	**260**	27
		5,941	4,028
Earnings (loss) before taxes		**(1,441)**	1,220
Current income tax (recovery) expense	12	**(179)**	165
Deferred income tax expense	12	**20**	94
Net earnings (loss)		**$ (1,282)**	$ 961
Net earnings (loss) per common share			
Basic	16	**$ (1.08)**	$ 0.80
Diluted	16	**$ (1.08)**	$ 0.80

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2020	Mar 31 2019
Net earnings (loss)	**$ (1,282)**	$ 961
Items that may be reclassified subsequently to net earnings (loss)		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $5 million (2019 – $5 million)	**39**	29
Reclassification to net earnings (loss), net of taxes of $1 million (2019 – $5 million)	**(7)**	(33)
	32	(4)
Foreign currency translation adjustment		
Translation of net investment	**254**	(60)
Other comprehensive income (loss), net of taxes	**286**	(64)
Comprehensive income (loss)	**$ (996)**	$ 897

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2020	Mar 31 2019
Share capital	13		
Balance – beginning of period		**$ 9,533**	$ 9,323
Issued upon exercise of stock options		**31**	83
Previously recognized liability on stock options exercised for common shares		**9**	4
Purchase of common shares under Normal Course Issuer Bid		**(56)**	(52)
Balance – end of period		**9,517**	9,358
Retained earnings			
Balance – beginning of period		**25,424**	22,529
Net earnings (loss)		**(1,282)**	961
Dividends on common shares	13	**(502)**	(449)
Purchase of common shares under Normal Course Issuer Bid	13	**(215)**	(189)
Balance – end of period		**23,425**	22,852
Accumulated other comprehensive income	14		
Balance – beginning of period		**34**	122
Other comprehensive income (loss), net of taxes		**286**	(64)
Balance – end of period		**320**	58
Shareholders' equity		**$ 33,262**	$ 32,268

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended Mar 31 2020	Three Months Ended Mar 31 2019
Operating activities			
Net earnings (loss)		**$ (1,282)**	$ 961
Non-cash items			
Depletion, depreciation and amortization		**1,564**	1,263
Share-based compensation		**(223)**	62
Asset retirement obligation accretion		**52**	44
Unrealized risk management (gain) loss		**(17)**	14
Unrealized foreign exchange loss (gain)		**1,121**	(233)
Realized foreign exchange gain on settlement of cross currency swaps		**(166)**	—
Loss from investments	8,9	**268**	35
Deferred income tax expense		**20**	94
Other		**(118)**	(120)
Abandonment expenditures		**(89)**	(108)
Net change in non-cash working capital		**595**	(1,016)
Cash flows from operating activities		**1,725**	996
Financing activities			
Issue of bank credit facilities and commercial paper, net	10	**649**	635
Proceeds on settlement of cross currency swaps	17	**166**	—
Payment of lease liabilities	7,11	**(65)**	(52)
Issue of common shares on exercise of stock options		**31**	83
Dividends on common shares		**(444)**	(403)
Purchase of common shares under Normal Course Issuer Bid	13	**(271)**	(241)
Cash flows from financing activities		**66**	22
Investing activities			
Net expenditures on exploration and evaluation assets		**(7)**	(33)
Net expenditures on property, plant and equipment		**(742)**	(836)
Net change in non-cash working capital		**(110)**	(160)
Cash flows used in investing activities		**(859)**	(1,029)
Increase (decrease) in cash and cash equivalents		**932**	(11)
Cash and cash equivalents – beginning of period		**139**	101
Cash and cash equivalents – end of period		**$ 1,071**	$ 90
Interest paid on long-term debt, net		**$ 213**	$ 228
Income taxes paid		**$ 41**	$ 226

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, 2019, 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, 2019.

Critical Accounting Estimates and Judgements

For the three months ended March 31, 2020, the novel coronavirus ("COVID-19") had an impact on the global economy, including the oil and gas industry. The Company has taken into account the impacts of COVID-19 and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements. Actual results may differ from estimated amounts, and those differences may be material.

2. CHANGES IN ACCOUNTING POLICIES

In October 2018, the IASB issued amendments to IFRS 3 "Definition of a Business" that narrowed and clarified the definition of a business. The amendments permit a simplified assessment of whether an acquired set of activities and assets is a group of assets rather than a business. The amendments apply to business combinations after the date of adoption. The Company prospectively adopted the amendments on January 1, 2020.

In October 2018, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" and IAS 8 "Accounting Policies, Changes in Accounting Estimates and Errors". The amendments make minor changes to the definition of the term "material" and align the definition across all IFRS Standards. Materiality is used in making judgments related to the preparation of financial statements. The Company prospectively adopted the amendments on January 1, 2020.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. The amendments are effective January 1, 2022 with early adoption permitted. The amendments are required to be adopted retrospectively. The Company is assessing the impact of these amendments on its consolidated financial statements.

4. INVENTORY

		Mar 31 2020		Dec 31 2019
Product inventory	**$**	**257**	$	468
Materials and supplies		**683**		684
	$	**940**	$	1,152

The Company recognized a provision of $77 million to report its product inventory at net realizable value as at March 31, 2020 (December 31, 2019 - $4 million).

5. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2019	$ 2,258	$ —	$ 69	$ 252	$ 2,579
Additions	**24**	**—**	**1**	**—**	**25**
Transfers to property, plant and equipment	**(32)**	**—**	**—**	**—**	**(32)**
Disposals/derecognitions	**(3)**	**—**	**—**	**—**	**(3)**
Foreign exchange adjustments	**—**	**—**	**3**	**—**	**3**
At March 31, 2020	**$ 2,247**	**$ —**	**$ 73**	**$ 252**	**$ 2,572**

6. 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, 2019	$ 72,627	$ 7,296	$ 3,933	$ 45,016	$ 451	$ 466	$ 129,789
Additions	**384**	**26**	**26**	**289**	**2**	**11**	**738**
Transfers from E&E assets	**32**	**—**	**—**	**—**	**—**	**—**	**32**
Change in asset retirement obligation estimates	**(794)**	**(114)**	**(29)**	**(332)**	**(1)**	**—**	**(1,270)**
Disposals/derecognitions	**(152)**	**—**	**—**	**(127)**	**—**	**—**	**(279)**
Foreign exchange adjustments and other	**—**	**654**	**352**	**—**	**—**	**—**	**1,006**
At March 31, 2020	**$ 72,097**	**$ 7,862**	**$ 4,282**	**$ 44,846**	**$ 452**	**$ 477**	**$ 130,016**
Accumulated depletion and depreciation							
At December 31, 2019	$ 46,577	$ 5,712	$ 2,712	$ 6,247	$ 153	$ 345	$ 61,746
Expense	**925**	**91**	**35**	**415**	**3**	**6**	**1,475**
Disposals/derecognitions	**(152)**	**—**	**—**	**(127)**	**—**	**—**	**(279)**
Foreign exchange adjustments and other	**(26)**	**503**	**244**	**12**	**—**	**—**	**733**
At March 31, 2020	**$ 47,324**	**$ 6,306**	**$ 2,991**	**$ 6,547**	**$ 156**	**$ 351**	**$ 63,675**
Net book value							
- at March 31, 2020	**$ 24,773**	**$ 1,556**	**$ 1,291**	**$ 38,299**	**$ 296**	**$ 126**	**$ 66,341**
- at December 31, 2019	$ 26,050	$ 1,584	$ 1,221	$ 38,769	$ 298	$ 121	$ 68,043

Given the recent change in the overall business environment and current uncertainties in the commodity markets, at March 31, 2020, the Company assessed the recoverability of its cash generating units ("CGUs"), based on externally available forward commodity prices and recently implemented cost reduction measures and the potential for further reductions as necessary. Based on the results of these assessments, the Company has determined the carrying value of all of its CGUs to be recoverable at March 31, 2020.

The Company will monitor the business environment, commodity markets, and the effectiveness of cost reduction measures throughout 2020, and will continue to assess the recoverability of the carrying value of its CGUs as appropriate.

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, 2020, pre-tax interest of $8 million (March 31, 2019 – $20 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.9% (March 31, 2019 – 4.1%).

7. LEASES

Lease assets

		Product transportation and storage		Field equipment and power		Offshore vessels and equipment		Office leases and other		Total
At December 31, 2019	$	1,166	$	317	$	182	$	124	$	1,789
Additions		**1**		**15**		**—**		**—**		**16**
Depreciation		**(30)**		**(14)**		**(20)**		**(7)**		**(71)**
Derecognitions		**(21)**		**(2)**		**(11)**		**—**		**(34)**
Foreign exchange adjustments and other		**(1)**		**(1)**		**17**		**2**		**17**
At March 31, 2020	**$**	**1,115**	**$**	**315**	**$**	**168**	**$**	**119**	**$**	**1,717**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at March 31, 2020 were as follows:

		Mar 31 2020		Dec 31 2019
Lease liabilities	**$**	**1,746**	$	1,809
Less: current portion		**221**		233
	$	**1,525**	$	1,576

Total cash outflows for leases for the three months ended March 31, 2020, including payments related to short-term leases not reported as lease assets, were $319 million (March 31, 2019 – $296 million). Interest expense on leases for the three months ended March 31, 2020 was $17 million (March 31, 2019 – $15 million).

8. INVESTMENTS

As at March 31, 2020, the Company had the following investments:

		Mar 31 2020		Dec 31 2019
Investment in PrairieSky Royalty Ltd.	**$**	**168**	$	345
Investment in Inter Pipeline Ltd.		**54**		145
	$	**222**	$	490

The loss (gain) from the investments was comprised as follows:

	Three Months Ended			
		Mar 31 2020		Mar 31 2019
Fair value loss (gain) from investments	**$**	**268**	$	(25)
Dividend income from investments		**(8)**		(8)
	$	**260**	$	(33)

The Company's investments in PrairieSky Royalty Ltd. ("PrairieSky") and Inter Pipeline Ltd. ("Inter Pipeline") do not constitute significant influence, and are accounted for at fair value through profit or loss, measured at each reporting date. As at March 31, 2020, the Company's investments in PrairieSky and Inter Pipeline were classified as current assets.

9. OTHER LONG-TERM ASSETS

	Mar 31 2020	Dec 31 2019
North West Redwater Partnership subordinated debt [(1)]	$ 668	$ 652
Prepaid cost of service toll	148	130
Risk management (note 17)	386	290
Long-term inventory	124	121
Other	165	84
	1,491	1,277
Less: current portion	226	54
	$ 1,265	$ 1,223

(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 after constructed, will operate a 50,000 barrel per day bitumen upgrader and refinery (the "Project") under processing agreements that target to process 12,500 barrels per day of bitumen feedstock for the Company and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta, under a 30 year fee-for-service tolling agreement.

During 2018, Redwater Partnership commenced commissioning activities in the Project's light oil units while continuing work on the heavy oil units. In 2019, the light oil units transitioned from pre-commissioning and startup to operations and are processing synthetic crude oil into refined products. In the first quarter of 2020, the Project continued to operate as a light oil refinery and will continue to process synthetic crude oil into refined products until the heavy oil units can reliably commence commercial processing of bitumen. As at March 31, 2020, the total estimate of capital costs incurred for the Project, net of margins from pre-commercial sales, was approximately $10 billion.

During 2013, the Company and APMC agreed, each with a 50% interest, to provide subordinated debt, bearing interest at prime plus 6%, as required for Project costs to reflect an agreed debt to equity ratio of 80/20. As at March 31, 2020, each party has provided $439 million of subordinated debt, together with accrued interest thereon of $229 million, for a Company total of $668 million. Any additional subordinated debt financing is not expected to be significant.

Pursuant to the processing agreements, on June 1, 2018 the Company began paying its 25% pro rata share of the debt portion of the monthly cost of service tolls, currently consisting of interest and fees, with principal repayments beginning in 2020 (see note 18). The Company is unconditionally obligated to pay this portion of the cost of service tolls over the 30-year tolling period. As at March 31, 2020, the Company had recognized $148 million in prepaid cost of service tolls (December 31, 2019 – $130 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 2021. As at March 31, 2020, Redwater Partnership had borrowings of $2,786 million under the syndicated credit facility.

During the fourth quarter of 2019, the carrying value of the Redwater Partnership investment was reduced to $nil. The unrecognized share of losses from the Redwater Partnership for the three months ended March 31, 2020 was $93 million (March 31, 2019 – recognized equity loss of $60 million). As at March 31, 2020, the cumulative unrecognized share of losses from the Redwater Partnership was $152 million (December 31, 2019 – $59 million).

10. LONG-TERM DEBT

		Mar 31 2020		Dec 31 2019
Canadian dollar denominated debt, unsecured				
Bank credit facilities	**$**	**2,496**	$	1,688
Medium-term notes		**4,300**		4,300
		6,796		5,988
US dollar denominated debt, unsecured				
Bank credit facilities (March 31, 2020 – US$3,677 million; December 31, 2019 - US$3,745 million)		**5,192**		4,855
Commercial paper (March 31, 2020 – US$nil; December 31, 2019 – US$254 million)		**—**		329
US dollar debt securities (March 31, 2020 – US$7,650 million; December 31, 2019 – US$7,650 million)		**10,802**		9,918
		15,994		15,102
Long-term debt before transaction costs and original issue discounts, net		**22,790**		21,090
Less: original issue discounts, net (1)		**17**		17
transaction costs (1) (2)		**86**		91
		22,687		20,982
Less: current portion of commercial paper		**—**		329
current portion of other long-term debt (1) (2)		**2,803**		2,062
	$	**19,884**	$	18,591

(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.

For the three months ended March 31, 2020, the Company reported an unrecognized foreign exchange loss of $1,049 million (March 31, 2019 – gain of $273 million) on its US dollar denominated debt, excluding the impact of hedging.

Bank Credit Facilities and Commercial Paper

As at March 31, 2020, the Company had in place revolving bank credit facilities of $4,959 million, of which $3,921 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,650 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $750 million non-revolving term credit facility maturing February 2021;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,250 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company’s North Sea operations.

Borrowings under the Company's non-revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, US base rate or Canadian prime rate. As at March 31, 2020, the non-revolving term credit facilities were fully drawn.

Subsequent to March 31, 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.

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

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

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

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2020 was 2.2% (March 31, 2019 – 2.6%), and on total long-term debt outstanding for the three months ended March 31, 2020 was 3.9% (March 31, 2019 – 4.1%).

As at March 31, 2020, letters of credit and guarantees aggregating to $469 million were outstanding.

Medium-Term Notes

In July 2019, 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 2021. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

US Dollar Debt Securities

In July 2019, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2021. 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.

11. OTHER LONG-TERM LIABILITIES

	Mar 31 2020	Dec 31 2019
Asset retirement obligations	**$ 4,551**	$ 5,771
Lease liabilities (note 7)	**1,746**	1,809
Deferred purchase consideration [(1)]	**71**	95
Share-based compensation	**64**	297
Risk management (note 17)	**4**	112
Other	**73**	98
	6,509	8,182
Less: current portion	**485**	819
	$ 6,024	$ 7,363

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

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.8% (December 31, 2019 – 3.8%) and inflation rates of up to 2% (December 31, 2019 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2020	Dec 31 2019
Balance – beginning of period	**$ 5,771**	$ 3,886
Liabilities incurred	**1**	15
Liabilities (disposed) acquired, net	**(1)**	198
Liabilities settled	**(89)**	(296)
Asset retirement obligation accretion	**52**	190
Change in discount rates	**(1,270)**	1,412
Foreign exchange adjustments	**87**	(46)
Revision of cost, inflation rates and timing estimates	**—**	412
Balance – end of period	**4,551**	5,771
Less: current portion	**181**	208
	$ 4,370	$ 5,563

Share-Based Compensation

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

The Company recognizes a liability for potential cash settlements under these plans. The current portion of the liability represents the maximum amount of the liability payable within the next twelve month period if all vested stock options and PSUs are settled in cash.

	Mar 31 2020	Dec 31 2019
Balance – beginning of period	**$ 297**	$ 124
Share-based compensation (recovery) expense	**(223)**	223
Cash payment for stock options surrendered	**(2)**	(2)
Transferred to common shares	**(9)**	(53)
Charged to Oil Sands Mining and Upgrading, net	**1**	5
Balance – end of period	**64**	297
Less: current portion	**40**	227
	$ 24	$ 70

Included within share-based compensation liability as at March 31, 2020 was $55 million related to PSUs granted to certain executive employees (December 31, 2019 – $62 million).

12. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
Expense (recovery)	**Mar 31 2020**	Mar 31 2019
Current corporate income tax – North America	**$ (194)**	$ 163
Current corporate income tax – North Sea	**9**	29
Current corporate income tax – Offshore Africa	**4**	12
Current PRT (1) – North Sea	**—**	(42)
Other taxes	**2**	3
Current income tax	**(179)**	165
Deferred income tax	**20**	94
Income tax	**$ (159)**	$ 259

(1) Petroleum Revenue Tax.

In the second quarter of 2019, the Government of Alberta enacted legislation that decreased the provincial corporate income tax rate from 12% to 11% effective July 2019, with a further 1% rate reduction every year on January 1 until the provincial corporate income tax rate is 8% on January 1, 2022.

13. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2020	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,186,857**	**$ 9,533**
Issued upon exercise of stock options	**967**	**31**
Previously recognized liability on stock options exercised for common shares	**—**	**9**
Purchase of common shares under Normal Course Issuer Bid	**(6,970)**	**(56)**
Balance – end of period	**1,180,854**	**$ 9,517**

Dividend Policy

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

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

Normal Course Issuer Bid

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

For the three months ended March 31, 2020, the Company purchased 6,970,000 common shares at a weighted average price of $38.84 per common share for a total cost of $271 million. Retained earnings were reduced by $215 million, representing the excess of the purchase price of common shares over their average carrying value.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2020:

	Three Months Ended Mar 31, 2020	
	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of period	**47,646**	**$ 38.04**
Granted	**11,082**	**$ 33.45**
Exercised for common shares	**(967)**	**$ 32.50**
Surrendered for cash settlement	**(315)**	**$ 34.04**
Forfeited	**(1,244)**	**$ 37.23**
Outstanding – end of period	**56,202**	**$ 37.26**
Exercisable – end of period	**17,054**	**$ 38.90**

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

14. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

		Mar 31 2020		Mar 31 2019
Derivative financial instruments designated as cash flow hedges	$	**103**	$	9
Foreign currency translation adjustment		**217**		49
	$	**320**	$	58

15. 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, 2020, the ratio was within the target range at 39.4%.

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 2020		Dec 31 2019
Long-term debt, net [1]	$	**21,616**	$	20,843
Total shareholders' equity	$	**33,262**	$	34,991
Debt to book capitalization		**39.4%**		37.3%

(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, 2020, the Company was in compliance with this covenant.

16. NET EARNINGS (LOSS) PER COMMON SHARE

			Three Months Ended		
			Mar 31 2020		Mar 31 2019
Weighted average common shares outstanding – basic (thousands of shares)			**1,183,138**		1,200,948
Effect of dilutive stock options (thousands of shares)			**—**		2,339
Weighted average common shares outstanding – diluted (thousands of shares)			**1,183,138**		1,203,287
Net earnings (loss)		$	**(1,282)**	$	961
Net earnings (loss) per common share	– basic	$	**(1.08)**	$	0.80
	– diluted	$	**(1.08)**	$	0.80

17. FINANCIAL INSTRUMENTS

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

	Mar 31, 2020				
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	**$ 1,281**	**$ —**	**$ —**	**$ —**	**$ 1,281**
Investments	**—**	**222**	**—**	**—**	**222**
Other long-term assets	**668**	**—**	**386**	**—**	**1,054**
Accounts payable	**—**	**—**	**—**	**(802)**	**(802)**
Accrued liabilities	**—**	**—**	**—**	**(2,214)**	**(2,214)**
Other long-term liabilities [1]	**—**	**(4)**	**—**	**(1,817)**	**(1,821)**
Long-term debt [2]	**—**	**—**	**—**	**(22,687)**	**(22,687)**
	$ 1,949	**$ 218**	**$ 386**	**$ (27,520)**	**$ (24,967)**

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

(1) Includes $1,746 million of lease liabilities (December 31, 2019 – $1,809 million) and $71 million of deferred purchase consideration payable over the next three years (December 31, 2019 – $95 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, 2020			
	Carrying amount	**Fair value**		
Asset (liability) [1] [2]		**Level 1**	**Level 2**	**Level 3** [4] [5]
Investments [3]	**$ 222**	**$ 222**	**$ —**	**$ —**
Other long-term assets	**$ 1,054**	**$ —**	**$ 386**	**$ 668**
Other long-term liabilities	**$ (75)**	**$ —**	**$ (4)**	**$ (71)**
Fixed rate long-term debt [6] [7]	**$ (14,999)**	**$ (12,686)**	**$ —**	**$ —**

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

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

(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 2020**		Dec 31 2019
Derivatives held for trading				
Natural gas AECO fixed price swaps	**$**	**(3)**	$	(3)
Foreign currency forward contracts		**(1)**		(10)
Natural gas AECO basis swaps		**—**		(8)
Cash flow hedges				
Foreign currency forward contracts		**135**		(91)
Cross currency swaps		**251**		290
	$	**382**	$	178
Included within:				
Current portion of other long-term assets	**$**	**143**	$	8
Current portion of other long-term liabilities		**(4)**		(112)
Other long-term assets		**243**		282
	$	**382**	$	178

For the three months ended March 31, 2020, the ineffectiveness arising from cash flow hedges was $nil (year ended December 31, 2019 – gain of $3 million).

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

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

Asset (liability)		**Mar 31 2020**		Dec 31 2019
Balance – beginning of period	**$**	**178**	$	356
Net change in fair value of outstanding derivative financial instruments recognized in:				
Risk management activities		**17**		(13)
Foreign exchange		**151**		(231)
Other comprehensive income		**36**		66
Balance – end of period		**382**		178
Less: current portion		**139**		(104)
	$	**243**	$	282

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

	Three Months Ended			
		Mar 31 2020		Mar 31 2019
Net realized risk management (gain) loss	**$**	**(47)**	$	27
Net unrealized risk management (gain) loss		**(17)**		14
	$	**(64)**	$	41

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, 2020, the Company had the following derivative financial instruments outstanding to manage its commodity price risk:

	Remaining term		Volume	Weighted average price	Index
Natural Gas					
AECO fixed price swaps	Apr 2020 –	Oct 2020	102,500 GJ/d	$1.51	AECO

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. At March 31, 2020, 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, 2020, the Company had the following cross currency swap contract outstanding:

	Remaining term			Amount	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Cross currency							
Swap	Apr 2020	–	Mar 2038	US$550	1.170	6.25%	5.76%

The cross currency swap derivative financial instrument was designated as a hedge at March 31, 2020 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at March 31, 2020, the Company had US$4,280 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,677 million designated as cash flow hedges.

During the first quarter of 2020, the Company settled the US$500 million cross currency swaps designated as cash flow hedges of the US$500 million 3.45% US dollar debt securities due November 2021. The Company realized cash proceeds of $166 million on settlement.

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, 2020, 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, 2020, the Company had net risk management assets of $383 million with specific counterparties related to derivative financial instruments (December 31, 2019 – $265 million).

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

c) Liquidity risk

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

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

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

		Less than 1 year		1 to less than 2 years		2 to less than 5 years		Thereafter
Accounts payable	$	802	$	—	$	—	$	—
Accrued liabilities	$	2,214	$	—	$	—	$	—
Long-term debt (1)	$	2,803	$	1,869	$	10,087	$	8,031
Other long-term liabilities (2)	$	250	$	188	$	412	$	971
Interest and other financing expense (3)	$	900	$	829	$	1,849	$	5,071

(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, $221 million; one to less than two years, $163 million; two to less than five years, $391 million; and thereafter $971 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at March 31, 2020.

18. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2020:

		Remaining 2020		2021		2022		2023		2024		Thereafter
Product transportation (1)	$	563	$	733	$	641	$	728	$	701	$	7,911
North West Redwater Partnership service toll (2)	$	113	$	168	$	162	$	160	$	154	$	2,828
Offshore vessels and equipment	$	57	$	70	$	10	$	—	$	—	$	—
Field equipment and power	$	24	$	21	$	20	$	21	$	20	$	249
Other	$	19	$	20	$	17	$	17	$	17	$	29

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

(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 tolls, which currently consists of interest and fees, with principal repayments beginning in 2020. Included in the cost of service tolls is $1,222 million of interest payable over the 30 year tolling period (see note 9).

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.

19. 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)	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales								
Crude oil and NGLs	**1,841**	1,839	**133**	134	**84**	109	**2,058**	2,082
Natural gas	**273**	375	**8**	25	**8**	18	**289**	418
Other [(1)]	**1**	2	**1**	—	**2**	1	**4**	3
Total segmented product sales	**2,115**	2,216	**142**	159	**94**	128	**2,351**	2,503
Less: royalties	**(114)**	(193)	**—**	—	**(4)**	(11)	**(118)**	(204)
Segmented revenue	**2,001**	2,023	**142**	159	**90**	117	**2,233**	2,299
Segmented expenses								
Production	**709**	602	**94**	67	**22**	18	**825**	687
Transportation, blending and feedstock	**1,070**	524	**7**	6	**—**	1	**1,077**	531
Depletion, depreciation and amortization	**955**	743	**99**	54	**41**	46	**1,095**	843
Asset retirement obligation accretion	**27**	20	**7**	7	**1**	1	**35**	28
Risk management activities (commodity derivatives)	**2**	31	**—**	—	**—**	—	**2**	31
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,763**	1,920	**207**	134	**64**	66	**3,034**	2,120
Segmented earnings (loss) before the following	**(762)**	103	**(65)**	25	**26**	51	**(801)**	179
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management activities (other)								
Foreign exchange loss (gain)								
Loss (gain) from investments								
Total non–segmented expenses								
Earnings (loss) before taxes								
Current income tax (recovery) expense								
Deferred income tax expense								
Net earnings (loss)								

	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)	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales								
Crude oil and NGLs [(2)]	**2,200**	2,854	**21**	21	**33**	125	**4,312**	5,082
Natural gas	**—**	—	**—**	—	**46**	38	**335**	456
Other [(1)]	**1**	—	**—**	—	**—**	—	**5**	3
Total segmented product sales	**2,201**	2,854	**21**	21	**79**	163	**4,652**	5,541
Less: royalties	**(34)**	(89)	**—**	—	**—**	—	**(152)**	(293)
Segmented revenue	**2,167**	2,765	**21**	21	**79**	163	**4,500**	5,248
Segmented expenses								
Production	**809**	822	**6**	6	**44**	15	**1,684**	1,530
Transportation, blending and feedstock [(2)]	**270**	360	**—**	—	**85**	148	**1,432**	1,039
Depletion, depreciation and amortization	**440**	417	**4**	3	**25**	—	**1,564**	1,263
Asset retirement obligation accretion	**17**	16	**—**	—	**—**	—	**52**	44
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**2**	31
Equity loss from investments	**—**	—	**—**	60	**—**	—	**—**	60
Total segmented expenses	**1,536**	1,615	**10**	69	**154**	163	**4,734**	3,967
Segmented earnings (loss) before the following	**631**	1,150	**11**	(48)	**(75)**	—	**(234)**	1,281
Non–segmented expenses								
Administration							**108**	70
Share-based compensation							**(223)**	62
Interest and other financing expense							**206**	191
Risk management activities (other)							**(66)**	10
Foreign exchange loss (gain)							**922**	(239)
Loss (gain) from investments							**260**	(33)
Total non–segmented expenses							**1,207**	61
Earnings (loss) before taxes							**(1,441)**	1,220
Current income tax (recovery) expense							**(179)**	165
Deferred income tax expense							**20**	94
Net earnings (loss)							**(1,282)**	961

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

(2) Includes blending and feedstock costs associated with the processing of third party bitumen and other purchased feedstock in the Oil Sands Mining and Upgrading segment.

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2020			Mar 31, 2019		
	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	**$ 6**	**$ (17)**	**$ (11)**	$ 30	$ (18)	$ 12
North Sea	**—**	**—**	**—**	—	—	—
Offshore Africa	**1**	**—**	**1**	3	—	3
	$ 7	**$ (17)**	**$ (10)**	$ 33	$ (18)	$ 15
Property, plant and equipment						
Exploration and Production						
North America	**$ 389**	**$ (919)**	**$ (530)**	$ 494	$ (101)	$ 393
North Sea	**26**	**(114)**	**(88)**	36	—	36
Offshore Africa [3]	**26**	**(29)**	**(3)**	64	(1,515)	(1,451)
	441	**(1,062)**	**(621)**	594	(1,616)	(1,022)
Oil Sands Mining and Upgrading [4]	**289**	**(459)**	**(170)**	234	(84)	150
Midstream and Refining	**1**	**—**	**1**	2	—	2
Head office	**11**	**—**	**11**	6	(3)	3
	$ 742	**$ (1,521)**	**$ (779)**	$ 836	$ (1,703)	$ (867)

(1) This table provides a reconciliation of capitalized costs, reported in note 5 and note 6, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

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

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

Segmented Assets

	Mar 31 2020	Dec 31 2019
Exploration and Production		
North America	**$ 30,042**	$ 30,963
North Sea	**1,660**	1,948
Offshore Africa	**1,580**	1,529
Other	**84**	30
Oil Sands Mining and Upgrading	**41,152**	42,006
Midstream and Refining	**1,333**	1,418
Head office	**228**	227
	$ 76,079	$ 78,121

SUPPLEMENTARY INFORMATION

INTEREST COVERAGE RATIOS

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

Interest coverage ratios for the twelve month period ended March 31, 2020:	
Interest coverage (times)	
Net earnings [(1)]	3.5x
Adjusted funds flow [(2)]	11.6x

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

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

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Corporate Information

Board of Directors

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Christopher L. Fong

Ambassador Gordon D. Giffin

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Senior Vice-President, Thermal

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Senior Vice-President, Marketing

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

David. B. Whitehouse
Vice-President and Managing Director, International

Barry Duncan
Vice-President, Finance, International

Stock Listing

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

Registrar and Transfer Agent

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