Canadian Natural

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2020 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2020 SECOND QUARTER RESULTS

Commenting on the Company's second quarter 2020 results, Tim McKay, President of Canadian Natural, stated "Canadian Natural is in a strong position as a result of our capital flexibility and continued focus on cost control, which maximizes margins in a volatile commodity price environment. The effectiveness of our strategies and our ability to execute on those strategies allows us to react quickly to changing markets and commodity price volatility.

In Q2/20, we delivered top tier operational results, producing approximately 1,165 MBOE/d, including liquids production of approximately 922 Mbbl/d, as our teams worked effectively to bring the majority of the voluntary curtailed volumes back on production in June 2020. Importantly, in our Oil Sands Mining and Upgrading assets, we achieved record quarterly production of high value Synthetic Crude Oil ("SCO") of approximately 464,300 bbl/d, inclusive of planned maintenance at Horizon in May. As well, we achieved record low Oil Sands Mining and Upgrading operating costs of $17.74/bbl (US$12.80/bbl) in Q2/20, a 15% decrease from Q1/20 levels, by continuing to focus on cost control.

In response to COVID-19, the Company implemented comprehensive precautions to ensure the health and safety of our workers while maintaining safe, reliable operations. We continue to focus on our environmental, social and governance ("ESG") performance throughout this volatility. ESG performance remains a top priority within the Company and there has been no change to our environmental targets set in December 2019, nor our environmental focused investments, which help reduce our environmental footprint and our GHG emissions, despite the economic impacts of COVID-19."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "The Company maintains a flexible and disciplined capital allocation strategy, with a focus on maintaining a strong financial position throughout the commodity price cycle. We have been proactive in managing our balance sheet and executing on our capital flexibility, with our targeted 2020 capital program on track at approximately $2.7 billion, while maintaining strong production levels throughout the year.

We generated adjusted funds flow of $415 million in Q2/20, reflecting the strength of the Company's long life low decline asset base, effective and efficient operations and our ability to maximize netbacks. Maximizing value for our shareholders, the Company elected to store as inventory at quarter end, a higher portion than normal of our SCO and International light crude oil production in the low commodity price quarter. If these barrels had been sold during the second quarter of 2020, based on June 2020 commodity prices, the Company would have generated approximately $60 million in additional cash flows from operating activities and adjusted funds flow in the quarter.

Our long life low decline assets continue to have industry leading low breakeven prices required to cover our low sustaining capital requirements and our current dividend, of approximately US$30 to US$31 WTI per barrel, reflecting our effective and efficient operations and our low to no reservoir risk, a distinct advantage in a volatile price environment. As a result, a small percentage of our total proved reserves are produced during challenging commodity price periods, resulting in very little impact to the Company's net asset value, thereby preserving long-term value for our shareholders and creditors.

At June 30, 2020, liquidity was strong at approximately $4.1 billion. As previously announced, in June we successfully completed the issue of two US dollar denominated bonds raising approximately $1.5 billion (US$1.1 billion). The Company's balance sheet remains resilient through this commodity price cycle, supported by strong investment grade credit ratings. In the second half of 2020, targeted free cash flow generation is significant, supporting a sustainable dividend and at current strip pricing targeted net debt at year end December 31, 2020 to be flat year-over-year."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2020	Mar 31 2020	Jun 30 2019	Six Months Ended Jun 30 2020	Jun 30 2019
Net earnings (loss)	**$ (310)**	$ (1,282)	$ 2,831	**$ (1,592)**	$ 3,792
Per common share – basic	**$ (0.26)**	$ (1.08)	$ 2.37	**$ (1.35)**	$ 3.17
– diluted	**$ (0.26)**	$ (1.08)	$ 2.36	**$ (1.35)**	$ 3.16
Adjusted net earnings (loss) from operations (1)	**$ (772)**	$ (295)	$ 1,042	**$ (1,067)**	$ 1,880
Per common share – basic	**$ (0.65)**	$ (0.25)	$ 0.87	**$ (0.90)**	$ 1.57
– diluted	**$ (0.65)**	$ (0.25)	$ 0.87	**$ (0.90)**	$ 1.57
Cash flows (used in) from operating activities	**$ (351)**	$ 1,725	$ 2,861	**$ 1,374**	$ 3,857
Adjusted funds flow (2)	**$ 415**	$ 1,337	$ 2,652	**$ 1,752**	$ 4,892
Per common share – basic	**$ 0.35**	$ 1.13	$ 2.22	**$ 1.48**	$ 4.09
– diluted	**$ 0.35**	$ 1.13	$ 2.22	**$ 1.48**	$ 4.08
Cash flows used in investing activities	**$ 693**	$ 859	$ 4,464	**$ 1,552**	$ 5,493
Net capital expenditures (3)	**$ 421**	$ 838	$ 4,125	**$ 1,259**	$ 5,102
Daily production, before royalties					
Natural gas (MMcf/d)	**1,462**	1,440	1,532	**1,451**	1,521
Crude oil and NGLs (bbl/d)	**921,895**	938,676	770,409	**930,286**	776,924
Equivalent production (BOE/d) (4)	**1,165,487**	1,178,752	1,025,800	**1,172,120**	1,030,480

(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 $310 million was realized in Q2/20, while the adjusted net loss in Q2/20 was $772 million.
- Cash flows used in operating activities were $351 million in Q2/20.
- Adjusted funds flow of $415 million in Q2/20 reflect the strength of the Company's long life low decline asset base and its effective and efficient operations.
  - Maximizing value for shareholders, the Company elected to store as inventory at quarter end, a higher portion than normal of its Synthetic Crude Oil ("SCO") and International light crude oil production in the low commodity price quarter. If these barrels had been sold during the second quarter of 2020, based on June 2020 commodity prices, the Company would have generated approximately $60 million in additional cash flows from operating activities and adjusted funds flow in the quarter.
- The Company reacted quickly to the changing commodity prices by executing planned maintenance and temporarily curtailing production when crude oil prices were low, optimizing its production mix and maximizing margins. Despite the impact of COVID-19 on the economy, Canadian Natural effectively executed on its curtailment optimization strategy, prioritizing its high netback SCO volumes, and achieved strong quarterly

production volumes of 1,165,487 BOE/d in Q2/20, an increase of 14% from Q2/19 and comparable to Q1/20 levels.

- Liquids production in Q2/20 was 921,895 bbl/d, an increase of 20% from Q2/19 and a decrease of 2% from Q1/20 levels. Increased production relative to Q2/19 reflects high utilization rates and safe, reliable operations in Oil Sands Mining and Upgrading, increased production from the acquisition of Jackfish and primary heavy crude oil assets in 2019 and the ramp up of Kirby North volumes.
  - Higher value light crude oil, NGLs and SCO production was prioritized in Q2/20, representing approximately 51% of total corporate BOE production volumes and will continue to be a key focus of the Company at current commodity price levels.
  - As a result of improved commodity prices, substantially all of the previously announced voluntarily curtailed production in the Company's thermal in situ and North America Exploration and Production ("E&P") crude oil and NGL areas was brought back on production in June 2020.
- At the Company's world class Oil Sands Mining and Upgrading assets, record quarterly production of 464,318 bbl/d of SCO was achieved in Q2/20. Increases over Q2/19 and Q1/20 levels of 24% and 6% respectively were achieved as a result of high utilization rates and operational enhancements at both Horizon and Athabasca Oil Sands Project ("AOSP"), partially offset by the impact from planned maintenance activities at Horizon in May 2020.
  - The Company's industry leading Oil Sands Mining and Upgrading assets achieved record low operating costs of $17.74/bbl (US$12.80/bbl) of SCO in Q2/20, representing decreases of 27% and 15% from Q2/19 and Q1/20 levels respectively. The record low operating costs in Q2/20 were primarily due to safe, reliable production, operational enhancements and continued focus on cost control.
  - At AOSP, as previously announced, the Scotford Upgrader ("Scotford") is targeting to increase upgrading capacity to approximately 320,000 bbl/d in Q3/20. Canadian Natural has increased gross production capacity at the Albian mines ("Albian") through optimization projects, process improvements, and enhanced reliability. In preparation for the increased capacity at Scotford, Canadian Natural confirmed Albian's ability to deliver incremental capacity in June 2020, during which time Albian gross production averaged approximately 339,000 bbl/d. This additional capacity at AOSP is targeted to provide Canadian Natural with increased margins and flexibility, maximizing the value of the Company's Oil Sands Mining and Upgrading assets.
- Canadian Natural's continued focus on delivering effective and efficient operations and cost control was also demonstrated as the Company's North American E&P liquids, including thermal in situ, achieved operating costs of $11.65/bbl (US$8.41/bbl) in Q2/20, decreases of 11% and 8% from Q2/19 and Q1/20 levels respectively.
- Thermal in situ production volumes averaged 212,807 bbl/d in Q2/20, a 94% increase over Q2/19 levels and a 7% decrease from Q1/20 levels. Production in Q2/20 increased relative to Q2/19 as a result of the Jackfish acquisition in 2019 and the strong ramp up of Kirby North. Production in Q2/20 decreased relative to Q1/20 as the Company temporarily curtailed volumes and accelerated maintenance activities into Q2/20 as a result of low commodity prices.
  - Thermal in situ operating costs were strong in Q2/20, averaging $10.13/bbl (US$7.31/bbl), decreases of 14% and 8% from Q2/19 and Q1/20 levels respectively. The Company maximized margins by prioritizing lower Steam to Oil Ratio ("SOR") production, capturing synergies from the Jackfish acquisition and lower power costs.
  - The ramp up of Kirby North is ahead of schedule and has been top tier with July 2020 production averaging approximately 43,200 bbl/d, exceeding the nameplate capacity of 40,000 bbl/d. Kirby North's low SOR of 2.3x in Q2/20 resulted in strong operating costs, maximizing margins within the Company's thermal in situ segment.
- North America natural gas production averaged 1,431 MMcf/d in Q2/20, a 3% decrease from Q2/19 levels and a 2% increase from Q1/20 levels. The increase from the prior quarter reflects the increased volumes from the Company's previously announced production additions and high reliability, offsetting natural declines. The Company continues to execute on its plan to add approximately 60 MMcf/d of highly economic natural gas volumes at less than $3,000 per flowing BOE and is on track to achieve the Company's annual incremental production target of approximately 35 MMcf/d.
  - North America natural gas operating costs were strong in Q2/20, averaging $1.11/Mcf, decreases of 3% and 10% from Q2/19 and Q1/20 levels respectively. These results demonstrate the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control and efficient operations.

- Canadian Natural maintained a strong financial position in Q2/20 with significant liquidity available at June 30, 2020 of approximately $4.1 billion, including credit facilities and cash balances. In addition, the Company has approximately $5.6 billion of availability under its United States (US$1.9 billion) and Canadian (C$3.0 billion) base shelf prospectuses, which expire August 2021, allowing the Company to offer these securities for sale from time to time. During Q2/20, the Company repaid $900 million of 2.05% medium-term notes and issued two US$ denominated notes raising approximately $1.5 billion (US$1.1 billion).
- The Government of Alberta enacted legislation in Q2/19 decreasing the provincial corporate income tax rate from 12% to 8% over time, commencing on July 1, 2019 through to 2022. In Q2/20, the Government of Alberta announced its intention to accelerate this legislation, lowering the current rate from 10% to 8% effective July 1, 2020. Canadian Natural estimates current tax savings for 2020 of approximately $35 million, including the reduction announced in 2019 and the acceleration in 2020. As a result of the tax rate reduction, the Company targets to invest these 2020 savings in economic projects across its Alberta operations. The acceleration of the tax rate reduction will also have an impact on 2021 current taxes and Canadian Natural will consider the tax savings for inclusion in 2021 investment.
- Canadian Natural appreciates the support from the Federal and Provincial governments and their commitment on getting oil and natural gas service providers back to work through the Abandonment and Reclamation Funding Program. Based on the total funding that has been announced to date by each province, the Company will be increasing its investment in abandonment programs in British Columbia, Saskatchewan and Alberta. The investments will be deployed to provide much needed jobs in each of the respective provinces.
- Canadian Natural is leading the crude oil and natural gas industry in Carbon Capture and Storage ("CCS") and sequestration initiatives and is one of the largest carbon dioxide ("CO_2") capturers and sequesterers for the oil and natural gas sector globally. As part of our comprehensive Greenhouse Gas ("GHG") emissions reduction strategy, our CCS projects include CO_2 storage in geological formations, use of CO_2 in enhanced oil recovery techniques and CO_2 injection into tailings. Gross carbon capture capacity through these projects combined is approximately 2.7 million tonnes of CO_2 annually, equivalent to taking approximately 576,000 vehicles off the road per year.
  - At the Company’s 70% owned Quest CCS facility located at Scotford, the facility captures and stores approximately 1.1 million tonnes of CO_2 per year. This highlights Canadian Natural’s leadership in leveraging technology and innovation and the strength of industry and government collaboration to continuously improve operational and environmental performance.
  - Canadian Natural has a 50% working interest in the North West Redwater Refinery, which combines gasification technology with an integrated carbon capture and storage program, capturing approximately 1.2 million tonnes of CO_2 per year and eliminating approximately 70% of the refinery's total carbon footprint. This project successfully reached commercial operations on June 1, 2020.
  - The Company has approximately 400,000 tonnes of CO_2 capture capacity per year for sequestration at Horizon by injecting CO_2 into its tailings ponds. This improves the Company's operating costs as a result of smaller tailings footprint and more efficient use of natural gas, as well as reduces GHG emissions and accelerates reclamation.

OPERATIONS REVIEW AND CAPITAL ALLOCATION

Canadian Natural has a balanced and diverse portfolio of assets, primarily Canadian-based, with international exposure in the UK section of the North Sea and Offshore Africa. Canadian Natural's production is well balanced between light crude oil, medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil) and Synthetic Crude Oil ("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, representing approximately 79% of the Company's total liquids production in Q2/20. 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 that 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	Six Months Ended June 30			
	2020		2019	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**43**	**37**	39	38
Natural gas	**13**	**12**	12	10
Dry	**—**	**—**	3	3
Subtotal	**56**	**49**	54	51
Stratigraphic test / service wells	**424**	**371**	379	335
Total	**480**	**420**	433	386
Success rate (excluding stratigraphic test / service wells)		**100%**		94%

- The Company's total crude oil and natural gas drilling program of 49 net wells for the six months ended June 30, 2020, excluding stratigraphic/service wells, represents a decrease of 2 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			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs production (bbl/d)	**200,699**	228,574	235,066	**214,637**	230,205
Net wells targeting crude oil	**2**	28	9	**30**	37
Net successful wells drilled	**2**	28	7	**30**	35
Success rate	**100%**	100%	78%	**100%**	95%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ, averaged 200,699 bbl/d, decreases of 15% and 12% from Q2/19 and Q1/20 levels respectively. The decrease in Q2/20 reflects the Company's decision to temporarily curtail production and reduce well servicing activities, as a result of low commodity prices in the quarter.

- Primary heavy crude oil production averaged 62,546 bbl/d in Q2/20, decreases of 19% and 24% from Q2/19 and Q1/20 levels respectively. The decrease in production was primarily as a result of temporarily curtailed production and reduced well servicing activity as a result of low commodity prices, as well as the execution of the Company's curtailment optimization strategy.
    - Operating costs in the Company's primary heavy crude oil operations in Q2/20 averaged $17.97/bbl (US$12.97/bbl), a 4% decrease from Q1/20 levels, as the Company continues to focus on cost control and maximizing margins.
- Pelican Lake production averaged 55,731 bbl/d in Q2/20, comparable to Q2/19 and a 4% decrease from Q1/20 levels. The decrease from Q1/20 is primarily due to reduced well servicing activity as a result of low crude oil prices in Q2/20.
    - The Company continues to demonstrate effective and efficient operations as Q2/20 operating costs at Pelican Lake of $6.31/bbl (US$4.55/bbl) decreased by 6% from Q2/19 levels and increased 2% from Q1/20 levels.
- North American light crude oil and NGL production averaged 82,422 bbl/d in Q2/20, decreases of 19% and 7% from Q2/19 and Q1/20 levels respectively, primarily as a result of temporarily curtailed production and reduced well servicing activity as a result of low commodity prices in Q2/20.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $14.41/bbl (US$10.40/bbl) in Q2/20, decreases of 2% and 10% from Q2/19 and Q1/20 levels respectively.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Bitumen production (bbl/d)	**212,807**	228,303	109,599	**220,555**	101,915
Net wells targeting bitumen	**—**	6	—	**6**	—
Net successful wells drilled	**—**	6	—	**6**	—
Success rate	**—**	100%	—	**100%**	—

- Thermal in situ production volumes averaged 212,807 bbl/d in Q2/20, a 94% increase over Q2/19 levels and a 7% decrease from Q1/20 levels. Production in Q2/20 increased relative to Q2/19 as a result of the Jackfish acquisition in 2019 and the strong ramp up of Kirby North. Production in Q2/20 decreased relative to Q1/20 as the Company temporarily curtailed volumes and accelerated maintenance activities into Q2/20 as a result of low commodity prices.
    - Thermal in situ operating costs were strong in Q2/20, averaging $10.13/bbl (US$7.31/bbl), decreases of 14% and 8% from Q2/19 and Q1/20 levels respectively. The Company maximized margins by prioritizing lower SOR production, capturing synergies from the Jackfish acquisition and lower power costs.
    - The ramp up of Kirby North is ahead of schedule and has been top tier with July 2020 production averaging approximately 43,200 bbl/d, exceeding the nameplate capacity of 40,000 bbl/d. Kirby North's low SOR of 2.3x in Q2/20 resulted in strong operating costs, maximizing margins within the Company's thermal in situ segment.
- At Kirby South, the solvent enhanced oil recovery technology pilot targets to increase oil recovery, reduce SOR by up to 50% and lower GHG intensity by up to 50%. To date, the Company continues to see positive results with increased bitumen production, lower SOR and high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Natural gas production (MMcf/d)	**1,431**	1,407	1,482	**1,419**	1,468
Net wells targeting natural gas	**1**	11	2	**12**	11
Net successful wells drilled	**1**	11	2	**12**	10
Success rate	**100%**	100%	100%	**100%**	91%

- North America natural gas production averaged 1,431 MMcf/d in Q2/20, a 3% decrease from Q2/19 levels and a 2% increase from Q1/20 levels. The increase from the prior quarter reflects the increased volumes from the Company's previously announced production additions, high reliability and strong base production, offsetting natural declines. The Company continues to execute on its plan to add approximately 60 MMcf/d of highly economic natural gas volumes at less than $3,000 per flowing BOE and is on track to achieve the Company's annual incremental production target of approximately 35 MMcf/d.
  - North America natural gas operating costs were strong in Q2/20, averaging $1.11/Mcf, decreases of 3% and 10% from Q2/19 and Q1/20 levels respectively. These results demonstrate the strength of the Company's strategy to own and control its infrastructure, continued focus on cost control and efficient operations.
  - At the Company's high value Septimus Montney liquids rich area, operating costs remained strong, averaging $0.31/Mcfe in Q2/20, a 6% decrease from Q2/19 levels.
- In Q2/20, Canadian Natural used the equivalent of approximately 49% of corporate annual natural gas production within its operations, providing a natural hedge from Western Canadian natural gas prices. Approximately 32% was exported to other North American markets and sold internationally, while the remaining 19% was exposed to AECO/Station 2 pricing.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil production (bbl/d)					
North Sea	**26,627**	27,755	27,594	**27,191**	26,659
Offshore Africa	**17,444**	15,943	23,650	**16,694**	22,907
Natural gas production (MMcf/d)					
North Sea	**15**	23	23	**19**	25
Offshore Africa	**16**	10	27	**13**	28
Net wells targeting crude oil	**—**	1.0	0.9	**1.0**	2.5
Net successful wells drilled	**—**	1.0	0.9	**1.0**	2.5
Success rate	**—**	100%	100%	**100%**	100%

- International E&P crude oil production volumes averaged 44,071 bbl/d in Q2/20, a decrease of 14% from Q2/19 levels and comparable to Q1/20 levels.
  - In the North Sea, crude oil production volumes averaged of 26,627 bbl/d in Q2/20, a decrease of 4% from both Q2/19 and Q1/20 levels as expected. Production in Q2/20 was lower, primarily as a result of the planned permanent cessation of production in the Banff and Kyle fields on June 1, 2020 and natural field declines. The Banff decommissioning project is on time and on budget.
    - Crude oil operating costs in the North Sea decreased by 24% and 4% from Q2/19 and Q1/20 levels respectively, averaging $28.47/bbl (US$20.55/bbl) in Q2/20. The decreases from the comparable periods

primarily reflected reduced maintenance activities, timing of liftings from various fields that have different cost structures and the Company's continued focus on cost control.

- Offshore Africa crude oil production volumes averaged 17,444 bbl/d in Q2/20, a decrease of 26% from Q2/19 levels and an increase of 9% from Q1/20 levels. The decrease in production from Q2/19 levels was primarily due to natural field declines. The increase in production from Q1/20 levels primarily reflects the successful completion of planned turnaround activities at Espoir in Q1/20.
  - Offshore Africa crude oil operating costs averaged $10.62/bbl (US$7.67/bbl) in Q2/20, an increase of 26% from Q2/19 and a decrease of 11% from Q1/20 levels. The changes in operating costs from the comparable periods primarily reflected fluctuations in production volumes on a relatively fixed cost base and the Company's continued focus on cost control.
  - In Q3/20, the operator is targeting to commence the drilling program of the previously announced discovery of significant gas condensate in South Africa, where Canadian Natural has a 20% working interest.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Synthetic crude oil production (bbl/d) (1) (2)	**464,318**	438,101	374,500	**451,210**	395,238

(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, record quarterly production of 464,318 bbl/d of SCO was achieved in Q2/20. Increases over Q2/19 and Q1/20 levels of 24% and 6% respectively were achieved as a result of high utilization rates and operational enhancements at both Horizon and AOSP, partially offset by the impact from planned maintenance activities at Horizon in May 2020.
  - The Company's industry leading Oil Sands Mining and Upgrading assets achieved record low operating costs of $17.74/bbl (US$12.80/bbl) of SCO in Q2/20, representing decreases of 27% and 15% from Q2/19 and Q1/20 levels respectively. The record low operating costs in Q2/20 are primarily due to safe, reliable production, operational enhancements and continued focus on cost control.
  - Oil Sands Mining and Upgrading reduced operating costs by approximately $84 million or 10% from Q2/19 levels to approximately $730 million in Q2/20, as a result of safe, reliable production, operational enhancements and continued focus on cost control.
- In the second half of 2020, the Company is targeting planned turnaround activities at both AOSP and Horizon. The Company's strength of operations and diverse asset base allows Canadian Natural to optimize maintenance activities within its Oil Sands Mining and Upgrading assets.
  - The turnaround at the non-operated Scotford Upgrader base plant began on July 8, 2020 and is targeted to be completed in 55 days, during which time the plant will run at restricted rates. Timing of maintenance activities at Albian is aligned with the turnaround at the Scotford Upgrader. During the turnaround, net production from AOSP is targeted to average approximately 100,000 bbl/d lower than normal.
  - At Horizon, the Company is targeting to begin a 20 day planned turnaround in mid-September. Monthly average production is targeted to be approximately 80,000 bbl/d lower than normal in September 2020 and October 2020.
- At AOSP, as previously announced, the Scotford Upgrader is targeting to increase upgrading capacity to approximately 320,000 bbl/d in Q3/20. Canadian Natural has increased gross production capacity at the Albian mines ("Albian") through optimization projects, process improvements, and enhanced reliability. In preparation for the increased capacity at Scotford, Canadian Natural confirmed Albian's ability to deliver incremental capacity in June 2020, during which time Albian gross production averaged approximately 339,000 bbl/d. This additional capacity at AOSP is targeted to provide Canadian Natural with increased margins and flexibility, maximizing the value of the Company's Oil Sands Mining and Upgrading assets.
- Commercial engineering of the In Pit Extraction Process ("IPEP") for Horizon continues, although the Company has temporarily delayed the field pilot in order to limit staffing levels to personnel who are critical to maintaining

safe, reliable operations in response to COVID-19 guidelines. Canadian Natural is confident in the results from the initial testing phase of the pilot, which shows excellent recovery rates and evidence of stackable tailings. The IPEP pilot will determine the feasibility of producing stackable dry tailings on a commercial basis. The project has the potential to reduce the Company's bitumen production GHG emissions by approximately 40% and lower the Company's environmental footprint by decreasing the handling of material, reducing the distance driven by its fleet of haul trucks, decreasing the size and need for tailings ponds and accelerating site reclamation. In addition, this process has the potential to reduce capital and operating costs.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) [1]	**$ 27.85**	$ 46.08	$ 59.83	**$ 36.97**	$ 57.38
WCS heavy differential as a percentage of WTI (%) [2]	**41%**	44%	18%	**43%**	20%
SCO price (US$/bbl)	**$ 23.28**	$ 43.39	$ 59.96	**$ 33.33**	$ 56.10
Condensate benchmark pricing (US$/bbl)	**$ 22.19**	$ 45.54	$ 55.86	**$ 33.86**	$ 53.19
Average realized pricing before risk management (C$/bbl) [3]	**$ 18.97**	$ 25.90	$ 63.45	**$ 22.70**	$ 59.05
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 1.81**	$ 2.03	$ 1.11	**$ 1.92**	$ 1.47
Average realized pricing before risk management (C$/Mcf)	**$ 2.03**	$ 2.22	$ 1.98	**$ 2.13**	$ 2.53

(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 many strengths when marketing its products, including a balanced and diverse product mix of natural gas, conventional heavy crude oil, conventional light crude oil, thermal in situ and SCO.
- Commodity prices continue to improve and Western Canadian Select ("WCS") differentials have tightened as a result of reduced activity in the Western Canadian Sedimentary Basin, production declines and price-related curtailments and shut-ins. Since June, WCS differentials to WTI remain relatively tight, with Q3/20 estimated to be approximately 22%. The Company continues to see sufficient egress in the foreseeable future as operators bring back on production volumes.
- Canadian Natural has 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 ("TMX") 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.
  - TMX construction continues to progress and is targeted to be on stream in late 2022.
  - Canadian Natural is committed to approximately 10,000 bbl/d of the targeted 50,000 bbl/d base Keystone export pipeline optimization expansion, which is targeted to be available in 2021.
- The North West Redwater Refinery reached commercial operations on June 1, 2020 and targets to process approximately 80,000 bbl/d of diluted bitumen, which will improve heavy oil demand in western Canada, effectively increasing egress out of the Western Canadian Sedimentary Basin. For more details, please contact the North West Redwater Partnership.

FINANCIAL REVIEW

The Company continues to implement proven strategies including 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 program, all support a flexible financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- The Company's strategy to maintain a diverse portfolio, balanced across various commodity types, achieved production of 1,165,487 BOE/d in Q2/20, with approximately 98% of total production located in G7 countries.
- Canadian Natural generated quarterly adjusted funds flow of $415 million in Q2/20, reflecting the strength of the Company's long life low decline asset base and its effective and efficient operations.
  - Maximizing value for shareholders, the Company elected to store as inventory at quarter end, a higher portion than normal of its SCO and International light crude oil production in the low commodity price quarter. If these barrels had been sold during the second quarter of 2020, based on June 2020 commodity prices, the Company would have generated approximately $60 million in additional cash flows from operating activities and adjusted funds flow in the quarter.
- Net capital expenditures in Q2/20 were disciplined at approximately $421 million.
- Returns to shareholders totaled $502 million in Q2/20 by way of dividends paid on April 1, 2020. As previously announced on March 18, 2020, the Company's share repurchase program has been suspended and the Board of Directors made the decision to not renew the Company's NCIB program, which expired in May 2020.
- Canadian Natural maintained a strong financial position in Q2/20 with significant liquidity available at June 30, 2020 of approximately $4.1 billion, including credit facilities and cash balances. The Company's liquidity is more than sufficient to retire, when due, any upcoming debt maturities.
  - In May 2020, 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 repaid $900 million of 2.05% medium-term notes that matured on June 1, 2020.
  - In June 2020, the Company issued two US$ denominated notes for total proceeds of approximately $1.5 billion (US$1.1 billion), including US$600 million of unsecured notes due in 2025 and US$500 million of unsecured notes due in 2030. Net proceeds from these notes were used primarily to refinance the Company's outstanding short-term indebtedness and for general corporate purposes.
  - The Company has approximately $5.6 billion of availability under its United States (US$1.9 billion) and Canadian (C$3.0 billion) base shelf prospectuses, which expire August 2021, allowing the Company to offer these securities for sale from time to time.
  - In addition to 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 $275 million and cross currency swaps with a total value of $206 million.
  - Debt to book capitalization and debt to adjusted EBITDA remained strong at 41.3% and 3.0x respectively.
- 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.
- 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.
  - Subsequent to quarter end, the Company declared a quarterly dividend of $0.425 per share, payable on October 5, 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 financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows (used in) 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 financial 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 financial measure adjusted funds flow is reconciled to cash flows (used in) from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of the Company's MD&A. The non-GAAP financial 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 9 - Long-term Debt in the Company’s consolidated financial statements.

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MANAGEMENT’S DISCUSSION AND ANALYSIS

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 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; the continued availability of the Canada Emergency Wage Subsidy ("CEWS") or other subsidies; 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 financial measures. The non-GAAP financial measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP financial measures to evaluate its performance. The non-GAAP financial measures should not be considered an alternative to or more meaningful than net earnings (loss), cash flows (used in) 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 financial 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 financial measure adjusted funds flow is reconciled to cash flows (used in) from operating activities, as determined in accordance with IFRS, in the "Financial Highlights" section of this MD&A. The non-GAAP financial measure net capital expenditures is reconciled to cash flows used in investing activities, as determined in accordance with IFRS, in the "Net Capital Expenditures" section of this MD&A. The Company also presents certain non-GAAP financial ratios and their derivation in the "Liquidity and Capital Resources" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the unaudited interim consolidated financial statements for the three and six months ended June 30, 2020 and the Company's MD&A and audited consolidated financial statements 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 and six months ended June 30, 2020 and this MD&A have been prepared in accordance with IFRS as issued by the International Accounting Standards Board ("IASB").

Production volumes and per unit statistics are presented throughout this MD&A on a "before 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 and six months ended June 30, 2020 in relation to the comparable periods in 2019 and the first quarter of 2020. 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. Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated August 5, 2020.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2020	Three Months Ended Mar 31 2020	Three Months Ended Jun 30 2019	Six Months Ended Jun 30 2020	Six Months Ended Jun 30 2019
Product sales [1]	**$ 2,944**	$ 4,652	$ 5,931	**$ 7,596**	$ 11,472
Crude oil and NGLs	**$ 2,462**	$ 4,323	$ 5,597	**$ 6,785**	$ 10,679
Natural gas	**$ 307**	$ 337	$ 324	**$ 644**	$ 780
Net earnings (loss)	**$ (310)**	$ (1,282)	$ 2,831	**$ (1,592)**	$ 3,792
Per common share – basic	**$ (0.26)**	$ (1.08)	$ 2.37	**$ (1.35)**	$ 3.17
– diluted	**$ (0.26)**	$ (1.08)	$ 2.36	**$ (1.35)**	$ 3.16
Adjusted net earnings (loss) from operations [2]	**$ (772)**	$ (295)	$ 1,042	**$ (1,067)**	$ 1,880
Per common share – basic	**$ (0.65)**	$ (0.25)	$ 0.87	**$ (0.90)**	$ 1.57
– diluted	**$ (0.65)**	$ (0.25)	$ 0.87	**$ (0.90)**	$ 1.57
Cash flows (used in) from operating activities	**$ (351)**	$ 1,725	$ 2,861	**$ 1,374**	$ 3,857
Adjusted funds flow [3]	**$ 415**	$ 1,337	$ 2,652	**$ 1,752**	$ 4,892
Per common share – basic	**$ 0.35**	$ 1.13	$ 2.22	**$ 1.48**	$ 4.09
– diluted	**$ 0.35**	$ 1.13	$ 2.22	**$ 1.48**	$ 4.08
Cash flows used in investing activities	**$ 693**	$ 859	$ 4,464	**$ 1,552**	$ 5,493
Net capital expenditures [4]	**$ 421**	$ 838	$ 4,125	**$ 1,259**	$ 5,102

(1) Further details related to product sales are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

(2) Adjusted net earnings (loss) from operations is a non-GAAP financial 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 financial measure that represents cash flows (used in) 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 (used in) 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 financial 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 Jun 30 2020	Mar 31 2020	Jun 30 2019	Six Months Ended Jun 30 2020	Jun 30 2019
Net earnings (loss)	**$ (310)**	$ (1,282)	$ 2,831	**$ (1,592)**	$ 3,792
Share-based compensation, net of tax (1)	**23**	(221)	(7)	**(198)**	55
Unrealized risk management loss (gain), net of tax (2)	**1**	(15)	(13)	**(14)**	—
Unrealized foreign exchange (gain) loss, net of tax (3)	**(433)**	1,121	(219)	**688**	(452)
Realized foreign exchange gain on settlement of cross currency swaps (4)	**—**	(166)	—	**(166)**	—
(Gain) loss from investments, net of tax (5) (6)	**(53)**	268	68	**215**	103
Effect of statutory tax rate and other legislative changes on deferred income tax liabilities (7)	**—**	—	(1,618)	**—**	(1,618)
Adjusted net earnings (loss) from operations	**$ (772)**	$ (295)	$ 1,042	**$ (1,067)**	$ 1,880

(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 ("NWRP") 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 NWRP's equity loss recognized for the period.

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

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

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

($ millions)	Three Months Ended Jun 30 2020	Mar 31 2020	Jun 30 2019	Six Months Ended Jun 30 2020	Jun 30 2019
Cash flows (used in) from operating activities	**$ (351)**	$ 1,725	$ 2,861	**$ 1,374**	$ 3,857
Net change in non-cash working capital	**739**	(595)	(230)	**144**	786
Abandonment expenditures (1)	**40**	89	41	**129**	149
Other (2)	**(13)**	118	(20)	**105**	100
Adjusted funds flow	**$ 415**	$ 1,337	$ 2,652	**$ 1,752**	$ 4,892

(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 six months ended June 30, 2020 was $1,592 million compared with net earnings of $3,792 million for the six months ended June 30, 2019. The net loss for the six months ended June 30, 2020 included net after-tax expenses of $525 million compared with net after-tax income of $1,912 million for the six months ended June 30, 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, loss from investments, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the six months ended June 30, 2020 was $1,067 million compared with adjusted net earnings from operations of $1,880 million for the six months ended June 30, 2019.

The net loss for the second quarter of 2020 was $310 million compared with net earnings of $2,831 million for the second quarter of 2019 and a net loss of $1,282 million for the first quarter of 2020. The net loss for the second quarter of 2020 included net after-tax income of $462 million compared with net after-tax income of $1,789 million for the second quarter of 2019 and net after-tax expenses of $987 million for the first quarter of 2020 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, (gain) loss from investments, and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities. Excluding these items, the adjusted net loss from operations for the second quarter of 2020 was $772 million compared with adjusted net earnings from operations of $1,042 million for the second quarter of 2019 and an adjusted net loss from operations of $295 million for the first quarter of 2020.

The net loss and adjusted net loss from operations for the three and six months ended June 30, 2020 compared with net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2019 primarily reflected:

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

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment;
- lower SCO production costs in the Oil Sands Mining and Upgrading segment; and
- higher sales volumes in the North America Exploration and Production segment.

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

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

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and
- lower SCO production costs in the Oil Sands Mining and Upgrading segment.

The impacts of share-based compensation, risk management activities and fluctuations in foreign exchange rates also contributed to the movements in net earnings (loss) from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A.

Cash Flows (used in) from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2020 were $1,374 million compared with $3,857 million for the six months ended June 30, 2019. Cash flows used in operating activities for the second quarter of 2020 were $351 million compared with cash flows from operating activities of $2,861 million for the second quarter of 2019 and $1,725 million for the first quarter of 2020. The fluctuations in cash flows (used in) from operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings (loss) and adjusted net earnings (loss) from operations (excluding the effects of depletion, depreciation and amortization and the impact of statutory tax rate and other legislative changes on deferred income tax liabilities), as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2020 was $1,752 million compared with $4,892 million for the six months ended June 30, 2019. Adjusted funds flow for the second quarter of 2020 was $415 million compared with $2,652 million for the second quarter of 2019 and $1,337 million for the first quarter of 2020. 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 (used in) 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 second quarter of 2020 increased 14% to 1,165,487 BOE/d from 1,025,800 BOE/d for the second quarter of 2019 and was comparable with 1,178,752 BOE/d for the first quarter of 2020. 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)		**Jun 30 2020**		Mar 31 2020		Dec 31 2019		Sep 30 2019
Product sales [1]	**$**	**2,944**	$	4,652	$	6,335	$	6,587
Crude oil and NGLs	**$**	**2,462**	$	4,323	$	5,947	$	6,324
Natural gas	**$**	**307**	$	337	$	382	$	257
Net earnings (loss)	**$**	**(310)**	$	(1,282)	$	597	$	1,027
Net earnings (loss) per common share								
– basic	**$**	**(0.26)**	$	(1.08)	$	0.50	$	0.87
– diluted	**$**	**(0.26)**	$	(1.08)	$	0.50	$	0.87
($ millions, except per common share amounts)		Jun 30 2019		Mar 31 2019		Dec 31 2018		Sep 30 2018
Product sales [1]	$	5,931	$	5,541	$	3,831	$	6,327
Crude oil and NGLs	$	5,597	$	5,082	$	3,327	$	5,967
Natural gas	$	324	$	456	$	504	$	360
Net earnings (loss)	$	2,831	$	961	$	(776)	$	1,802
Net earnings (loss) per common share								
– basic	$	2.37	$	0.80	$	(0.64)	$	1.48
– diluted	$	2.36	$	0.80	$	(0.64)	$	1.47

(1) Further details related to product sales for the three months ended June 30, 2020 and 2019 are disclosed in note 18 to the Company's unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from 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 and disposition 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 NWRP.
- **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 half of 2020 due to the erosion of global demand, reflecting the severity of COVID-19 and related economic conditions. In response to the collapse of oil prices in April 2020, OPEC and Russia agreed to cut 9.7 MMbbl/d of production through July 2020. Following these actions, pricing improved in the latter half of the quarter with June 2020 WTI benchmark pricing averaging US$38.31 per bbl and the WCS Heavy Differential averaging US$4.34 per bbl. Subsequent to quarter end, in July 2020, WTI benchmark pricing averaged US$40.77 per bbl and the WCS Heavy Differential averaged US$8.27 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 implemented changes to its compensation program in light of current commodity volatility, and these changes had an immediate impact on the Company's costs, effective April 2020. The Company is also working diligently to reduce production costs wherever possible, asking all stakeholders to contribute to the sustainability of operations.

In the second quarter of 2020, the Company prioritized the optimization of higher value light crude oil, NGLs and SCO, representing approximately 51% of total corporate BOE production volumes. Optimization of production volumes continues to be a key focus of the Company at current commodity price levels.

Production costs in the second 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.

Canada Emergency Wage Subsidy

On March 27, 2020, in response to COVID-19, the Government of Canada announced the CEWS. The CEWS enables eligible Canadian employers who have been impacted by COVID-19 to apply for a subsidy of up to 75% of eligible employee wages under this program. The Company was eligible for the subsidy as its qualifying revenues declined by in excess of 30% in the second quarter of 2020 as compared to the second quarter of 2019.

Liquidity

As at June 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,879 million was available. Including cash and cash equivalents and other liquidity, the Company had approximately $4,112 million in available liquidity. During the second quarter of 2020, the Company repaid $900 million of 2.05% medium-term notes and issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030.

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 the first quarter of 2020, as a result of the volatility in crude oil pricing, the Company reduced its capital spending budget to approximately $2,960 million. In the second quarter of 2020, 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

(Average for the period)	Three Months Ended **Jun 30 2020**	Three Months Ended Mar 31 2020	Three Months Ended Jun 30 2019	Six Months Ended **Jun 30 2020**	Six Months Ended Jun 30 2019
WTI benchmark price (US$/bbl)	**$ 27.85**	$ 46.08	$ 59.83	**$ 36.97**	$ 57.38
Dated Brent benchmark price (US$/bbl)	**$ 31.38**	$ 50.42	$ 68.36	**$ 40.90**	$ 65.87
WCS Heavy Differential from WTI (US$/bbl)	**$ 11.53**	$ 20.47	$ 10.65	**$ 16.00**	$ 11.51
SCO price (US$/bbl)	**$ 23.28**	$ 43.39	$ 59.96	**$ 33.33**	$ 56.10
Condensate benchmark price (US$/bbl)	**$ 22.19**	$ 45.54	$ 55.86	**$ 33.86**	$ 53.19
Condensate Differential from WTI (US$/bbl)	**$ 5.66**	$ 0.54	$ 3.96	**$ 3.11**	$ 4.18
NYMEX benchmark price (US$/MMBtu)	**$ 1.72**	$ 1.95	$ 2.64	**$ 1.84**	$ 2.89
AECO benchmark price (C$/GJ)	**$ 1.81**	$ 2.03	$ 1.11	**$ 1.92**	$ 1.47
US/Canadian dollar average exchange rate (US$)	**$ 0.7218**	$ 0.7434	$ 0.7474	**$ 0.7324**	$ 0.7498

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$36.97 per bbl for the six months ended June 30, 2020, a decrease of 36% from US$57.38 per bbl for the six months ended June 30, 2019. WTI averaged US$27.85 per bbl for the second quarter of 2020, a decrease of 53% from US$59.83 per bbl for the second quarter of 2019, and a decrease of 40% from US$46.08 per bbl for the first quarter of 2020.

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$40.90 per bbl for the six months ended June 30, 2020, a decrease of 38% from US$65.87 per bbl for the six months ended June 30, 2019. Brent averaged US$31.38 per bbl for the second quarter of 2020, a decrease of 54% from US$68.36 per bbl for the second quarter of 2019, and a decrease of 38% from US$50.42 per bbl for the first quarter of 2020.

The decrease in WTI and Brent pricing for the three and six months ended June 30, 2020 from the comparable periods primarily reflected significant reductions in refinery utilization due to decreased demand as a result of COVID-19, resulting in an oversupply of crude oil in the market. During the second quarter of 2020, OPEC and Russia came to an agreement to reduce supply, which partially mitigated the significant decline in crude oil pricing.

The WCS Heavy Differential averaged US$16.00 per bbl for the six months ended June 30, 2020, an increase of 39% from US$11.51 per bbl for the six months ended June 30, 2019. The WCS Heavy Differential averaged US$11.53 per bbl for the second quarter of 2020, an increase of 8% from US$10.65 per bbl for the second quarter of 2019, and a decrease of 44% from US$20.47 per bbl for the first quarter of 2020. The narrowing of the WCS Heavy Differential for the second quarter of 2020 from the first quarter of 2020 primarily reflected reduced benchmark pricing as well as the impact of a significant reduction in supply from the Basin. The WCS Heavy Differential in the current and the comparable periods also reflected the impact of the mandatory curtailment program.

The SCO price averaged US$33.33 per bbl for the six months ended June 30, 2020, a decrease of 41% from US$56.10 per bbl for the six months ended June 30, 2019. The SCO price averaged US$23.28 per bbl for the second quarter of 2020, a decrease of 61% from US$59.96 per bbl for the second quarter of 2019, and a decrease of 46%

from US$43.39 per bbl for the first quarter of 2020. The decrease in the SCO price for the three and six months ended June 30, 2020 from the comparable periods primarily reflected a decrease in WTI benchmark pricing.

NYMEX natural gas prices averaged US$1.84 per MMBtu for the six months ended June 30, 2020, a decrease of 36% from US$2.89 per MMBtu for the six months ended June 30, 2019. NYMEX natural gas prices averaged US$1.72 per MMBtu for the second quarter of 2020, a decrease of 35% from US$2.64 per MMBtu for the second quarter of 2019, and a decrease of 12% from US$1.95 per MMBtu for the first quarter of 2020. The decrease in NYMEX natural gas prices for the three and six months ended June 30, 2020 from the comparable periods primarily reflected production levels exceeding North American demand due to decreasing Liquefied Natural Gas ("LNG") exports and the impact of COVID-19, together with the impact of milder weather conditions.

AECO natural gas prices averaged $1.92 per GJ for the six months ended June 30, 2020, an increase of 31% from $1.47 per GJ for the six months ended June 30, 2019. AECO natural gas prices averaged $1.81 per GJ for the second quarter of 2020, an increase of 63% from $1.11 per GJ for the second quarter of 2019, and a decrease of 11% from $2.03 per GJ for the first quarter of 2020. The increase in AECO natural gas prices for the three and six months ended June 30, 2020 from the comparable periods in 2019 primarily reflected low storage levels and the impact of the TC Energy Temporary Service Protocol. The decrease in AECO natural gas prices for the second quarter of 2020 from the first quarter of 2020 primarily reflected seasonal demand factors.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**413,506**	456,877	344,665	**435,191**	332,120
North America – Oil Sands Mining and Upgrading (1)	**464,318**	438,101	374,500	**451,210**	395,238
North Sea	**26,627**	27,755	27,594	**27,191**	26,659
Offshore Africa	**17,444**	15,943	23,650	**16,694**	22,907
	921,895	938,676	770,409	**930,286**	776,924
Natural gas (MMcf/d)					
North America	**1,431**	1,407	1,482	**1,419**	1,468
North Sea	**15**	23	23	**19**	25
Offshore Africa	**16**	10	27	**13**	28
	1,462	1,440	1,532	**1,451**	1,521
Total barrels of oil equivalent (BOE/d)	**1,165,487**	1,178,752	1,025,800	**1,172,120**	1,030,480
Product mix					
Light and medium crude oil and NGLs	**11%**	11%	15%	**11%**	14%
Pelican Lake heavy crude oil	**5%**	5%	5%	**5%**	6%
Primary heavy crude oil	**5%**	7%	8%	**6%**	7%
Bitumen (thermal oil)	**18%**	20%	11%	**19%**	10%
Synthetic crude oil (1)	**40%**	37%	36%	**38%**	38%
Natural gas	**21%**	20%	25%	**21%**	25%
Percentage of gross revenue (1) (2) (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**89%**	92%	95%	**91%**	93%
Natural gas	**11%**	8%	5%	**9%**	7%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**379,554**	414,460	307,413	**397,007**	294,395
North America – Oil Sands Mining and Upgrading	**462,143**	432,936	354,975	**447,539**	376,189
North Sea	**26,567**	27,693	27,525	**27,130**	26,605
Offshore Africa	**16,739**	15,296	22,694	**16,017**	21,484
	885,003	890,385	712,607	**887,693**	718,673
Natural gas (MMcf/d)					
North America	**1,399**	1,374	1,427	**1,387**	1,414
North Sea	**15**	23	23	**19**	25
Offshore Africa	**15**	10	25	**12**	25
	1,429	1,407	1,475	**1,418**	1,464
Total barrels of oil equivalent (BOE/d)	**1,123,221**	1,124,839	958,499	**1,124,029**	962,605

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 six months ended June 30, 2020 averaged 930,286 bbl/d, an increase of 20% from 776,924 bbl/d for the six months ended June 30, 2019. Crude oil and NGLs production for the second quarter of 2020 of 921,895 bbl/d increased 20% from 770,409 bbl/d for the second quarter of 2019, and was comparable with 938,676 bbl/d for the first quarter of 2020. The increase in crude oil and NGLs production for the six months ended June 30, 2020 from the six months ended June 30, 2019 primarily reflected production from the acquisition of thermal and heavy oil assets from Devon and high utilization rates and operational enhancements in the Oil Sands Mining and Upgrading segment. The increase in crude oil and NGLs production for the second quarter of 2020 from the second quarter of 2019 primarily reflected record production in the Oil Sands Mining and Upgrading segment in the second quarter, together with added production from the acquisition of thermal and heavy oil assets from Devon.

Production in the three and six months ended June 30, 2020 and comparable periods reflected the impact of mandatory Government of Alberta curtailment.

Natural gas production before royalties for the six months ended June 30, 2020 decreased 5% to 1,451 MMcf/d from 1,521 MMcf/d for the six months ended June 30, 2019. Natural gas production for the second quarter of 2020 of 1,462 MMcf/d decreased 5% from 1,532 MMcf/d for the second quarter of 2019, and increased slightly from 1,440 MMcf/d for the first quarter of 2020. The decrease in natural gas production for the three and six months ended June 30, 2020 from the comparable periods in 2019 primarily reflected natural field declines. The increase in natural gas production for the second quarter of 2020 from the first quarter of 2020 reflected the impact of added natural gas volumes due to opportunities identified by the Company.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the six months ended June 30, 2020 averaged 435,191 bbl/d, an increase of 31% from 332,120 bbl/d for the six months ended June 30, 2019. North America crude oil and NGLs production for the second quarter of 2020 of 413,506 bbl/d increased 20% from 344,665 bbl/d for the second quarter of 2019, and decreased 9% from 456,877 bbl/d for the first quarter of 2020. The increase in production for the three and six months ended June 30, 2020 from the comparable periods in 2019 primarily reflected the acquisition of thermal and heavy oil assets from Devon. The decrease in production for the second quarter of 2020 from the first quarter of 2020 was primarily due to the Company's response to lower crude oil pricing, including maintenance activities in thermal, reduced well servicing activities, and the temporary reduction and shut in of certain crude oil fields. Production in the three and six months ended June 30, 2020 and comparable periods reflected the impact of mandatory Government of Alberta curtailment.

Thermal oil production before royalties for the second quarter of 2020 averaged 212,807 bbl/d, an increase of 94% from 109,599 bbl/d for the second quarter of 2019, and a decrease of 7% from 228,303 bbl/d for the first quarter of 2020. The increase in thermal oil production from the second quarter of 2019 primarily reflected the impact of production from the acquisition from Devon, together with new production from Kirby North and pad additions at Primrose. The decrease in thermal oil production from the first quarter of 2020 primarily reflected temporary voluntary curtailment of thermal production volumes and accelerated maintenance activities in response to low commodity pricing.

Pelican Lake heavy crude oil production before royalties averaged 55,731 bbl/d for the second quarter of 2020 comparable with 55,031 bbl/d for the second quarter of 2019 and a decrease of 4% from 57,986 bbl/d for the first quarter of 2020, reflecting reduced well servicing activities in response to lower crude oil pricing, together with the field's low natural decline rate.

Natural gas production before royalties for the six months ended June 30, 2020 decreased 3% to 1,419 MMcf/d from 1,468 MMcf/d for the six months ended June 30, 2019. Natural gas production for the second quarter of 2020 averaged 1,431 MMcf/d, a decrease of 3% from 1,482 MMcf/d for the second quarter of 2019, and a slight increase from 1,407 MMcf/d for the first quarter of 2020. The decrease in natural gas production for the three and six months ended June 30, 2020 from the comparable periods in 2019 primarily reflected natural field declines. The increase in natural gas production for the second quarter of 2020 from the first quarter of 2020 reflected the impact of added natural gas volumes due to opportunities identified by the Company.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2020 of 451,210 bbl/d increased 14% from 395,238 bbl/d for the six months ended June 30, 2019. SCO production for the second quarter of 2020 increased 24% to average 464,318 bbl/d from 374,500 bbl/d for the second quarter of 2019 and increased 6% from 438,101 bbl/d for the first quarter of 2020. The increase in production for the three and six months ended June 30, 2020 from the comparable periods was due to high utilization rates and operational enhancements at both Horizon and AOSP, partially offset by the impact of planned maintenance activities at Horizon in May 2020.

North Sea

North Sea crude oil production before royalties for the six months ended June 30, 2020 of 27,191 bbl/d was comparable with 26,659 bbl/d for the six months ended June 30, 2019. North Sea crude oil production for the second quarter of 2020 decreased 4% to 26,627 bbl/d from 27,594 bbl/d for the second quarter of 2019 and decreased 4% from 27,755 bbl/d for the first quarter of 2020. The decrease in production for the three months ended June 30, 2020 from the comparable periods was primarily due to the permanent cessation of production at the Banff and Kyle fields on June 1, 2020, as well as natural field declines.

Offshore Africa

Offshore Africa crude oil production before royalties for the six months ended June 30, 2020 decreased 27% to 16,694 bbl/d from 22,907 bbl/d for the six months ended June 30, 2019. Offshore Africa crude oil production for the second quarter of 2020 of 17,444 bbl/d decreased 26% from 23,650 bbl/d for the second quarter of 2019 and increased 9% from 15,943 bbl/d for the first quarter of 2020. The decrease in production for the three and six months ended June 30, 2020 from the comparable periods in 2019 was primarily due to natural field declines. The increase in production for the second quarter of 2020 from the first quarter of 2020 primarily reflected the successful completion of planned turnaround activities at Espoir in the first quarter of 2020.

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)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019
North Sea	**190,135**	—	969,651
Offshore Africa	**1,375,747**	532,347	1,076,772
	1,565,882	532,347	2,046,423

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 18.97**	$ 25.90	$ 63.45	**$ 22.70**	$ 59.05
Transportation	**4.20**	3.87	3.35	**4.02**	3.31
Realized sales price, net of transportation	**14.77**	22.03	60.10	**18.68**	55.74
Royalties	**1.48**	2.34	6.35	**1.94**	6.17
Production expense	**12.53**	13.71	14.42	**13.17**	15.17
Netback	**$ 0.76**	$ 5.98	$ 39.33	**$ 3.57**	$ 34.40
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 2.03**	$ 2.22	$ 1.98	**$ 2.13**	$ 2.53
Transportation	**0.41**	0.46	0.40	**0.44**	0.43
Realized sales price, net of transportation	**1.62**	1.76	1.58	**1.69**	2.10
Royalties	**0.05**	0.05	0.08	**0.05**	0.10
Production expense	**1.15**	1.31	1.23	**1.23**	1.28
Netback	**$ 0.42**	$ 0.40	$ 0.27	**$ 0.41**	$ 0.72
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 16.57**	$ 21.90	$ 43.38	**$ 19.37**	$ 41.42
Transportation	**3.61**	3.50	2.97	**3.55**	3.03
Realized sales price, net of transportation	**12.96**	18.40	40.41	**15.82**	38.39
Royalties	**1.05**	1.70	4.06	**1.40**	3.92
Production expense	**10.55**	11.87	11.68	**11.24**	12.15
Netback	**$ 1.36**	$ 4.83	$ 24.67	**$ 3.18**	$ 22.32

(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			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 17.22**	$ 23.48	$ 59.45	**$ 20.57**	$ 55.39
North Sea	**$ 45.60**	$ 45.85	$ 88.25	**$ 45.74**	$ 88.00
Offshore Africa	**$ 29.40**	$ 58.16	$ 95.33	**$ 48.35**	$ 89.79
Average	**$ 18.97**	$ 25.90	$ 63.45	**$ 22.70**	$ 59.05
Natural gas ($/Mcf) (1) (2)					
North America	**$ 1.97**	$ 2.15	$ 1.84	**$ 2.06**	$ 2.35
North Sea	**$ 1.42**	$ 3.75	$ 5.34	**$ 2.81**	$ 7.96
Offshore Africa	**$ 8.75**	$ 8.94	$ 6.94	**$ 8.83**	$ 7.14
Average	**$ 2.03**	$ 2.22	$ 1.98	**$ 2.13**	$ 2.53
Average ($/BOE) (1) (2)	**$ 16.57**	$ 21.90	$ 43.38	**$ 19.37**	$ 41.42

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

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

North America

North America realized crude oil prices decreased 63% to average $20.57 per bbl for the six months ended June 30, 2020 from $55.39 per bbl for the six months ended June 30, 2019. North America realized crude oil prices averaged $17.22 per bbl for the second quarter of 2020, a decrease of 71% compared with $59.45 per bbl for the second quarter of 2019, and a decrease of 27% compared with $23.48 per bbl for the first quarter of 2020. The decrease in realized crude oil prices for the three and six months ended June 30, 2020 from the comparable periods was primarily due to lower WTI benchmark pricing due to decreased demand as a result of COVID-19, resulting in an oversupply of crude oil in the market, together with fluctuations in the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2020 contributed approximately 136,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 12% to average $2.06 per Mcf for the six months ended June 30, 2020 from $2.35 per Mcf for the six months ended June 30, 2019. North America realized natural gas prices increased 7% to average $1.97 per Mcf for the second quarter of 2020 from $1.84 per Mcf for the second quarter of 2019, and decreased 8% from $2.15 per Mcf for the first quarter of 2020. The decrease in realized natural gas prices for the three and six months ended June 30, 2020 from the six months ended June 30, 2019 and the first quarter of 2020 primarily reflected production levels exceeding North American demand due to decreasing LNG exports and the impact of COVID-19, together with the impact of milder weather conditions. The increase in realized natural gas prices for the second quarter of 2020 from the second quarter of 2019 primarily reflected low storage levels and the impact of the TC Energy Temporary Service Protocol.

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

	Three Months Ended		
(Quarterly average)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 20.36**	$ 38.15	$ 53.23
Pelican Lake heavy crude oil ($/bbl)	**$ 20.98**	$ 27.75	$ 66.71
Primary heavy crude oil ($/bbl)	**$ 17.98**	$ 25.01	$ 64.71
Bitumen (thermal oil) ($/bbl)	**$ 14.79**	$ 16.53	$ 57.61
Natural gas ($/Mcf)	**$ 1.97**	$ 2.15	$ 1.84

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

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

North Sea

North Sea realized crude oil prices of $45.74 per bbl for the six months ended June 30, 2020 decreased 48% from $88.00 per bbl for the six months ended June 30, 2019. North Sea realized crude oil prices decreased 48% to average $45.60 per bbl for the second quarter of 2020 from $88.25 per bbl for the second quarter of 2019 and was comparable with $45.85 per bbl for the first quarter of 2020. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 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 46% to average $48.35 per bbl for the six months ended June 30, 2020 from $89.79 per bbl for the six months ended June 30, 2019. Offshore Africa realized crude oil prices decreased 69% to average $29.40 per bbl for the second quarter of 2020 from $95.33 per bbl for the second quarter of 2019 and decreased 49% from $58.16 per bbl for the first quarter of 2020. Realized crude oil prices per barrel in any particular period are dependent on the terms of the various sales contracts, the frequency and timing of liftings from each field, and prevailing crude oil prices and foreign exchange rates at the time of lifting. The fluctuations in realized crude oil prices for the three and six months ended June 30, 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			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 1.56**	$ 2.49	$ 6.99	**$ 2.06**	$ 6.62
North Sea	**$ 0.10**	$ 0.10	$ 0.22	**$ 0.10**	$ 0.18
Offshore Africa	**$ 1.19**	$ 2.36	$ 3.85	**$ 1.96**	$ 5.04
Average	**$ 1.48**	$ 2.34	$ 6.35	**$ 1.94**	$ 6.17
Natural gas ($/Mcf) (1)					
North America	**$ 0.04**	$ 0.05	$ 0.07	**$ 0.05**	$ 0.09
Offshore Africa	**$ 0.40**	$ 0.51	$ 0.59	**$ 0.44**	$ 0.72
Average	**$ 0.05**	$ 0.05	$ 0.08	**$ 0.05**	$ 0.10
Average ($/BOE) (1)	**$ 1.05**	$ 1.70	$ 4.06	**$ 1.40**	$ 3.92

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

North America

North America crude oil and natural gas royalties for the three and six months ended June 30, 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 10% of product sales for the six months ended June 30, 2020 compared with 12% of product sales for the six months ended June 30, 2019. Crude oil and NGLs royalty rates averaged approximately 9% of product sales for the second quarter of 2020 compared with 12% for the second quarter of 2019 and 11% for the first quarter of 2020. The decrease in royalty rates for the three and six months ended June 30, 2020 from the comparable periods primarily reflected lower benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 2% of product sales for the six months ended June 30, 2020 compared with 4% of product sales for the six months ended June 30, 2019. Natural gas royalty rates averaged approximately 2% of product sales for the first and second quarter of 2020 compared with 4% for the second quarter of 2019. The decrease in royalty rates for the second quarter of 2020 from the second quarter of 2019 primarily reflected royalty adjustments, offsetting the impact of higher realized natural gas prices.

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 six months ended June 30, 2020, compared with 6% of product sales for the six months ended June 30, 2019. Royalty rates as a percentage of product sales averaged approximately 4% for the second quarter of 2020, compared with 4% of product sales for the second quarter of 2019 and the first quarter of 2020. 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			Six Months Ended	
	Jun 30 2020	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Crude oil and NGLs ($/bbl) [(1)]					
North America	**$ 11.65**	$ 12.69	$ 13.10	**$ 12.20**	$ 14.03
North Sea	**$ 28.47**	$ 29.73	$ 37.31	**$ 29.19**	$ 38.24
Offshore Africa	**$ 10.62**	$ 11.88	$ 8.40	**$ 11.45**	$ 8.93
Average	**$ 12.53**	$ 13.71	$ 14.42	**$ 13.17**	$ 15.17
Natural gas ($/Mcf) [(1)]					
North America	**$ 1.11**	$ 1.24	$ 1.15	**$ 1.17**	$ 1.22
North Sea	**$ 3.18**	$ 3.45	$ 5.09	**$ 3.34**	$ 3.60
Offshore Africa	**$ 3.46**	$ 5.56	$ 2.49	**$ 4.30**	$ 2.30
Average	**$ 1.15**	$ 1.31	$ 1.23	**$ 1.23**	$ 1.28
Average ($/BOE) [(1)]	**$ 10.55**	$ 11.87	$ 11.68	**$ 11.24**	$ 12.15

(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 six months ended June 30, 2020 averaged $12.20 per bbl, a decrease of 13% from $14.03 per bbl for the six months ended June 30, 2019. North America crude oil and NGLs production expense for the second quarter of 2020 of $11.65 per bbl decreased 11% from $13.10 per bbl for the second quarter of 2019 and decreased 8% from $12.69 per bbl for the first quarter of 2020. The decrease in crude oil and NGLs production expense per barrel for the three and six months ended June 30, 2020 from the comparable periods primarily reflected the impact of operating cost synergies captured to date combined with added production from the acquisition of assets from Devon, Kirby North and pad additions at Primrose, and the Company's continuous focus on cost control and achieving efficiencies across the entire asset base. The decrease for the second quarter of 2020 from the first quarter of 2020 reflected the impact of seasonality.

North America natural gas production expense for the six months ended June 30, 2020 averaged $1.17 per Mcf, a decrease of 4% from $1.22 per Mcf for the six months ended June 30, 2019. North America natural gas production expense for the second quarter of 2020 of $1.11 per Mcf decreased 3% from $1.15 per Mcf for the second quarter of 2019 and decreased 10% from $1.24 per Mcf for the first quarter of 2020. The decrease in natural gas production expense per Mcf for the three and six months ended June 30, 2020 from the comparable periods primarily reflected the Company's continued focus on cost control and increased volumes processed in strategically owned and operated infrastructure. The decrease for the second quarter of 2020 from the first quarter of 2020 reflected the impact of seasonality.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2020 decreased 24% to $29.19 per bbl from $38.24 per bbl for the six months ended June 30, 2019. North Sea crude oil production expense for the second quarter of 2020 of $28.47 per bbl decreased 24% from $37.31 per bbl for the second quarter of 2019 and decreased 4% from $29.73 per bbl for the first quarter of 2020. The decrease in crude oil production expense per bbl for the three and six months ended June 30, 2020 from the comparable periods primarily reflected reduced maintenance activities due to COVID-19, the Company's continuous focus on cost control, and the timing of liftings from various fields that have different cost structures. North Sea production expense also reflected fluctuations in the Canadian dollar.

Offshore Africa

Offshore Africa crude oil production expense for the six months ended June 30, 2020 increased 28% to $11.45 per bbl from $8.93 per bbl for the six months ended June 30, 2019. Offshore Africa crude oil production expense for the second quarter of 2020 of $10.62 per bbl increased 26% from $8.40 per bbl for the second quarter of 2019 and decreased 11% from $11.88 per bbl for the first quarter of 2020. The changes in production expense per bbl for the three and six months ended June 30, 2020 from the comparable periods primarily reflected fluctuations in production volumes on a relatively fixed cost base, the Company's continuous focus on cost control, and fluctuations in the Canadian dollar. The increase in production expense for the six months ended June 30, 2020 from the six months ended June 30, 2019 also reflected the timing of liftings from various fields that have different cost structures.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense	**$ 974**	$ 1,095	$ 929	**$ 2,069**	$ 1,772
$/BOE [(1)]	**$ 15.47**	$ 15.75	$ 15.60	**$ 15.62**	$ 15.58

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2020 of $15.62 per BOE was comparable with $15.58 per BOE for the six months ended June 30, 2019. Depletion, depreciation and amortization expense for the second quarter of 2020 of $15.47 per BOE was comparable with $15.60 per BOE for the second quarter of 2019 and $15.75 per BOE for the first quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense	**$ 33**	$ 35	$ 31	**$ 68**	$ 59
$/BOE [(1)]	**$ 0.53**	$ 0.50	$ 0.49	**$ 0.51**	$ 0.52

(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 six months ended June 30, 2020 of $0.51 per BOE was comparable with $0.52 per BOE for the six months ended June 30, 2019. Asset retirement obligation accretion expense for the second quarter of 2020 of $0.53 per BOE increased 8% from $0.49 per BOE for the second quarter of 2019, and increased 6% from $0.50 per BOE for the first quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per BOE basis primarily reflect fluctuating sales volumes.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable and efficient operations and leveraging its technical expertise across the Horizon and AOSP sites. Record production in the second quarter of 2020 averaged 464,318 bbl/d due to high utilization rates and operational enhancements at both Horizon and AOSP, partially offset by the impact of planned maintenance activities at Horizon in May 2020.

The Company achieved production costs of $730 million for the second quarter of 2020, a 10% decrease from the second quarter of 2019 and the first quarter of 2020. 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			Six Months Ended	
($/bbl) (1)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
SCO realized sales price (2)	**$ 29.11**	$ 50.88	$ 74.98	**$ 39.71**	$ 70.12
Bitumen value for royalty purposes (3)	**$ 18.35**	$ 16.82	$ 58.74	**$ 17.60**	$ 53.16
Bitumen royalties (4)	**$ 0.15**	$ 0.87	$ 3.79	**$ 0.50**	$ 3.00
Transportation	**$ 0.97**	$ 1.28	$ 1.53	**$ 1.12**	$ 1.34

(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 $39.71 per bbl for the six months ended June 30, 2020, a decrease of 43% from $70.12 per bbl for the six months ended June 30, 2019. For the second quarter of 2020, the realized sales price decreased 61% to $29.11 per bbl from $74.98 per bbl for the second quarter of 2019 and decreased 43% from $50.88 per bbl for the first quarter of 2020. The decrease in the realized SCO sales price for the three and six months ended June 30, 2020 from the comparable periods primarily reflected a decrease in WTI benchmark pricing.

Transportation expense averaged $1.12 per bbl for the six months ended June 30, 2020, a decrease of 16% from $1.34 per bbl for the six months ended June 30, 2019. For the second quarter of 2020, transportation expense decreased 37% to $0.97 per bbl from $1.53 per bbl for the second quarter of 2019 and decreased 24% from $1.28 per bbl for the first quarter of 2020. The decrease in transportation expense for the three and six months ended June 30, 2020 from the comparable periods primarily reflected increased production volumes, together with lower pipeline charges for the second quarter of 2020.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Production costs, excluding natural gas costs	**$ 699**	$ 773	$ 789	**$ 1,472**	$ 1,568
Natural gas costs	**31**	36	25	**67**	68
Production costs	**$ 730**	$ 809	$ 814	**$ 1,539**	$ 1,636

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Production costs, excluding natural gas costs	**$ 16.98**	$ 19.83	$ 23.45	**$ 18.37**	$ 21.79
Natural gas costs	**0.76**	0.93	0.72	**0.84**	0.94
Production costs	**$ 17.74**	$ 20.76	$ 24.17	**$ 19.21**	$ 22.73
Sales (bbl/d)	**452,066**	428,515	369,846	**440,290**	397,664

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

Production costs for the six months ended June 30, 2020 decreased 15% to $19.21 per bbl from $22.73 per bbl for the six months ended June 30, 2019. Production costs for the second quarter of 2020 averaged $17.74 per bbl, a decrease of 27% from $24.17 per bbl for the second quarter of 2019 and a decrease of 15% from $20.76 per bbl for the first quarter of 2020.

The decrease in production costs for the three and six months ended June 30, 2020 from the comparable periods primarily reflected high utilization rates and operational enhancements at both Horizon and AOSP, partially offset by planned maintenance activities at Horizon in May 2020. The Company continued to focus on cost control and efficiencies across the entire asset base.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense	**$ 451**	$ 440	$ 374	**$ 891**	$ 791
$/bbl (1)	**$ 10.97**	$ 11.28	$ 11.12	**$ 11.12**	$ 10.99

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

Depletion, depreciation and amortization expense for the six months ended June 30, 2020 of $11.12 per bbl was comparable with $10.99 per bbl for the six months ended June 30, 2019. Depletion, depreciation and amortization expense for the second quarter of 2020 of $10.97 per bbl was comparable with $11.12 per bbl for the second quarter of 2019, and decreased 3% from $11.28 per bbl for the first quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Six Months Ended	
($ millions, except per bbl amounts)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense	**$ 18**	$ 17	$ 15	**$ 35**	$ 31
$/bbl (1)	**$ 0.44**	$ 0.44	$ 0.46	**$ 0.44**	$ 0.43

(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 six months ended June 30, 2020 of $0.44 per bbl was comparable with $0.43 per bbl for the six months ended June 30, 2019. Asset retirement obligation accretion expense of $0.44 per bbl for the second quarter of 2020 decreased 4% from $0.46 per bbl for the second quarter of 2019 and was comparable with $0.44 per bbl for the first quarter of 2020. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended **Jun 30 2020**	Mar 31 2020	Jun 30 2019	Six Months Ended **Jun 30 2020**	Jun 30 2019
Product sales					
Crude oil and NGLs, midstream activities	**$ 20**	$ 21	$ 20	**$ 41**	$ 41
NWRP, refined product sales	**25**	—	—	**25**	—
Segmented revenue	**45**	21	20	**66**	41
Less:					
Production expenses					
NWRP, refining toll	**24**	—	—	**24**	—
Midstream	**5**	6	5	**11**	11
NWRP, transportation and feedstock costs	**22**	—	—	**22**	—
Depreciation	**3**	4	4	**7**	7
Equity loss from investment in NWRP	**—**	—	66	**—**	126
Segmented earnings (loss) before taxes	**$ (9)**	$ 11	$ (55)	**$ 2**	$ (103)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose and the Company's 50% interest in the NWRP.

NWRP operates a 50,000 bbl/d bitumen upgrader and refinery that targets 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, an agent of the Government of Alberta, under a 30-year fee-for-service tolling agreement.

The Company's unrecognized share of equity losses from NWRP for the three months ended June 30, 2020 was $23 million (six months ended June 30, 2020 – unrecognized equity loss of $116 million). As at June 30, 2020, the cumulative unrecognized share of losses from NWRP was $175 million (December 31, 2019 – $59 million).

On June 1, 2020 the refinery achieved the Commercial Operation Date ("COD"), pursuant to the terms of the tolling agreement. Following COD, the Company is unconditionally obligated to pay its 25% pro rata share of the debt tolls over the 30-year tolling period. For the month of June, production of ultra-low sulphur diesel and other refined products averaged 55,748 BOE/d (13,937 BOE/d to the Company).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended **Jun 30 2020**	Mar 31 2020	Jun 30 2019	Six Months Ended **Jun 30 2020**	Jun 30 2019
Expense	**$ 88**	$ 108	$ 84	**$ 196**	$ 154
$/BOE (1)	**$ 0.84**	$ 1.00	$ 0.90	**$ 0.92**	$ 0.83

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

Administration expense for the six months ended June 30, 2020 of $0.92 per BOE increased 11% from $0.83 per BOE for the six months ended June 30, 2019. Administration expense for the second quarter of 2020 of $0.84 per BOE decreased 7% from $0.90 per BOE for the second quarter of 2019 and decreased 16% from $1.00 per BOE for the first quarter of 2020. Administration expense per BOE increased for the six months ended June 30, 2020 from the six months ended June 30, 2019 primarily due to the impact of the acquisition of assets from Devon, together with lower overhead recoveries. Administration expense per BOE decreased for the second quarter of 2020 from the second quarter of 2019 primarily due to higher sales volumes. Administration expense per BOE decreased for the second quarter of 2020 from the first quarter of 2020 due to higher personnel costs in the first quarter of 2020.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense (recovery)	**$ 23**	$ (223)	$ (7)	**$ (200)**	$ 55

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 $200 million share-based compensation recovery for the six months ended June 30, 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 six months ended June 30, 2020 was a recovery of $6 million related to PSUs granted to certain executive employees (June 30, 2019 – $17 million expense). For the six months ended June 30, 2020, the Company charged $3 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (June 30, 2019 – $3 million charged).

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts and interest rates)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Expense, gross	**$ 206**	$ 214	$ 214	**$ 420**	$ 425
Less: capitalized interest	**7**	8	17	**15**	37
Expense, net	**$ 199**	$ 206	$ 197	**$ 405**	$ 388
$/BOE (1)	**$ 1.91**	$ 1.90	$ 2.12	**$ 1.90**	$ 2.09
Average effective interest rate	**3.5%**	3.9%	4.1%	**3.7%**	4.1%

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

Gross interest and other financing expense for the three months ended June 30, 2020 decreased from the comparable periods primarily due to lower interest rates, partially offset by the impact of higher average debt levels. Capitalized interest of $15 million for the six months ended June 30, 2020 was related to residual project activities at Horizon.

Net interest and other financing expense for the six months ended June 30, 2020 decreased 9% to $1.90 per BOE from $2.09 per BOE for the six months ended June 30, 2019. Net interest and other financing expense per BOE for the second quarter of 2020 decreased 10% to $1.91 per BOE from $2.12 per BOE for the second quarter of 2019 and was comparable with $1.90 per BOE for the first quarter of 2020. The decrease in net interest and other financing expense per BOE for the three and six months ended June 30, 2020 from the comparable periods in 2019 was primarily due to lower average interest rates, partially offset by the impact of lower capitalized interest.

The Company's average effective interest rate for the second quarter of 2020 decreased from the comparable periods primarily due to the impact of lower benchmark interest rates on the Company's outstanding bank credit facilities and US commercial paper program.

RISK MANAGEMENT ACTIVITIES

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

($ millions)	Three Months Ended **Jun 30 2020**	Three Months Ended Mar 31 2020	Three Months Ended Jun 30 2019	Six Months Ended **Jun 30 2020**	Six Months Ended Jun 30 2019
Foreign currency contracts	**$ 28**	$ (57)	$ 16	**$ (29)**	$ 16
Natural gas financial instruments	**3**	10	(2)	**13**	(3)
Crude oil and NGLs financial instruments	**—**	—	13	**—**	41
Net realized loss (gain)	**31**	(47)	27	**(16)**	54
Foreign currency contracts	**—**	(9)	(2)	**(9)**	7
Natural gas financial instruments	**1**	(8)	1	**(7)**	1
Crude oil and NGLs financial instruments	**—**	—	(15)	**—**	(10)
Net unrealized loss (gain)	**1**	(17)	(16)	**(16)**	(2)
Net loss (gain)	**$ 32**	$ (64)	$ 11	**$ (32)**	$ 52

During the six months ended June 30, 2020, net realized risk management gains were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized gain of $16 million ($14 million after-tax) on its risk management activities for the six months ended June 30, 2020, including an unrealized loss of $1 million ($1 million after-tax) for the second quarter of 2020 (March 31, 2020 – unrealized gain of $17 million, $15 million after-tax; June 30, 2019 – unrealized gain of $16 million, $13 million after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2020 are disclosed in note 16 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended **Jun 30 2020**	Three Months Ended Mar 31 2020	Three Months Ended Jun 30 2019	Six Months Ended **Jun 30 2020**	Six Months Ended Jun 30 2019
Net realized loss (gain)	**$ 3**	$ (199)	$ 2	**$ (196)**	$ (4)
Net unrealized (gain) loss	**(433)**	1,121	(219)	**688**	(452)
Net (gain) loss (1)	**$ (430)**	$ 922	$ (217)	**$ 492**	$ (456)

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

The net realized foreign exchange gain for the six months ended June 30, 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 first quarter of 2020. The net unrealized foreign exchange loss for the six months ended June 30, 2020 was primarily related to the impact of a weaker Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss 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 in the first quarter of 2020 (three months ended June 30, 2020 – unrealized loss of $28 million, March 31, 2020 – unrealized loss of $74 million, June 30, 2019 – unrealized loss of $28 million; six months ended June 30, 2020 – unrealized loss of $102 million, June 30, 2019 – unrealized loss of $58 million). The US/Canadian dollar exchange rate at June 30, 2020 was US$0.7345 (March 31, 2020 – US$0.7082, June 30, 2019 – US$0.7639).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2020	Mar 31 2020	Jun 30 2019	Six Months Ended Jun 30 2020	Jun 30 2019
North America [1]	**$ (34)**	$ (194)	$ 78	**$ (228)**	$ 241
North Sea	**1**	9	28	**10**	57
Offshore Africa	**2**	4	11	**6**	23
PRT [2] – North Sea	**—**	—	(43)	**—**	(85)
Other taxes	**—**	2	3	**2**	6
Current income tax (recovery) expense	**(31)**	(179)	77	**(210)**	242
Deferred corporate income tax (recovery) expense	**(267)**	20	(1,359)	**(247)**	(1,265)
Deferred PRT [2] – North Sea	**—**	—	1	**—**	1
Deferred income tax (recovery) expense	**(267)**	20	(1,358)	**(247)**	(1,264)
Income tax recovery	**(298)**	(159)	(1,281)	**(457)**	(1,022)
Income tax rate and other legislative changes	**—**	—	1,618	**—**	1,618
	$ (298)	$ (159)	$ 337	**$ (457)**	$ 596
Effective income tax rate on adjusted net earnings (loss) from operations [3]	**28%**	36%	26%	**30%**	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 three and six months ended June 30, 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 six months ended June 30, 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 Jun 30 2020	Mar 31 2020	Jun 30 2019	Six Months Ended Jun 30 2020	Jun 30 2019
Exploration and Evaluation					
Net property (dispositions) acquisitions [2]	**$ —**	$ (18)	$ 91	**$ (18)**	$ 92
Net expenditures	**1**	25	37	**26**	69
Total Exploration and Evaluation	**1**	7	128	**8**	161
Property, Plant and Equipment					
Net property acquisitions [2]	**2**	13	3,134	**15**	3,158
Well drilling, completion and equipping	**32**	202	171	**234**	425
Production and related facilities	**78**	214	271	**292**	558
Capitalized interest and other	**14**	12	23	**26**	52
Total Property, Plant and Equipment	**126**	441	3,599	**567**	4,193
Total Exploration and Production	**127**	448	3,727	**575**	4,354
Oil Sands Mining and Upgrading					
Project costs	**49**	56	106	**105**	182
Sustaining capital	**172**	201	210	**373**	350
Turnaround costs	**20**	23	17	**43**	25
Capitalized interest and other	**9**	9	9	**18**	19
Total Oil Sands Mining and Upgrading	**250**	289	342	**539**	576
Midstream and Refining	**2**	1	3	**3**	5
Abandonments [3]	**40**	89	41	**129**	149
Head office	**2**	11	12	**13**	18
Total net capital expenditures	**$ 421**	$ 838	$ 4,125	**$ 1,259**	$ 5,102
By segment					
North America [2]	**$ 95**	$ 395	$ 3,612	**$ 490**	$ 4,136
North Sea	**17**	26	42	**43**	78
Offshore Africa	**15**	27	73	**42**	140
Oil Sands Mining and Upgrading	**250**	289	342	**539**	576
Midstream and Refining	**2**	1	3	**3**	5
Abandonments [3]	**40**	89	41	**129**	149
Head office	**2**	11	12	**13**	18
Total	**$ 421**	$ 838	$ 4,125	**$ 1,259**	$ 5,102

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

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

(3) 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			Six Months Ended	
($ millions)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Cash flows used in investing activities	***$ 693***	*$ 859*	*$ 4,464*	***$ 1,552***	*$ 5,493*
Net change in non-cash working capital [1]	***(312)***	*(110)*	*(380)*	***(422)***	*(540)*
Abandonment expenditures [2]	***40***	*89*	*41*	***129***	*149*
Net capital expenditures	***$ 421***	*$ 838*	*$ 4,125*	***$ 1,259***	*$ 5,102*

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

(2) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows (used in) 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 six months ended June 30, 2020 were $1,259 million as compared with $5,102 million for the six months ended June 30, 2019. Net capital expenditures for the second quarter of 2020 were $421 million, compared with $4,125 million for the second quarter of 2019 and $838 million for the first quarter of 2020.

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 the first quarter of 2020, as a result of the volatility in crude oil pricing, the Company reduced its capital spending budget to approximately $2,960 million. In the second quarter of 2020, the budget was further reduced to approximately $2,680 million, a $1,370 million reduction from the original 2020 budget.

Drilling Activity [1]

	Three Months Ended			Six Months Ended	
(number of net wells)	**Jun 30 2020**	Mar 31 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Net successful natural gas wells	**1**	11	2	**12**	10
Net successful crude oil wells [2]	**2**	35	8	**37**	38
Dry wells	**—**	—	2	**—**	3
Stratigraphic test / service wells	**4**	367	3	**371**	335
Total	**7**	413	15	**420**	386
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	83%	**100%**	94%

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

(2) Includes bitumen wells.

North America

During the second quarter of 2020, the Company targeted 1 net natural gas well and 2 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Jun 30 2020**	Mar 31 2020	Dec 31 2019	Jun 30 2019
Working capital (1)	**$ 993**	$ 683	$ 241	$ 709
Long-term debt (2) (3)	**$ 23,020**	$ 22,687	$ 20,982	$ 23,507
Less: cash and cash equivalents	**233**	1,071	139	398
Long-term debt, net	**$ 22,787**	$ 21,616	$ 20,843	$ 23,109
Share capital	**$ 9,521**	$ 9,517	$ 9,533	$ 9,320
Retained earnings	**22,614**	23,425	25,424	24,927
Accumulated other comprehensive income	**198**	320	34	27
Shareholders' equity	**$ 32,333**	$ 33,262	$ 34,991	$ 34,274
Debt to book capitalization (3) (4)	**41.3%**	39.4%	37.3%	40.3%
Debt to market capitalization (3) (5)	**45.0%**	48.7%	29.5%	35.4%
After-tax return on average common shareholders' equity (6)	**0.1%**	9.4%	16.1%	14.7%
After-tax return on average capital employed (3) (7)	**1.2%**	6.8%	10.9%	9.9%

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

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

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

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

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

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

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

As at June 30, 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 market conditions. 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 the parental guarantees or letter of credits 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:
    - During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.

- During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030.
- After issuing these securities, the Company had US$1,900 million remaining on its 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.
- During the second quarter of 2020, the Company repaid $900 million of 2.05% 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.
- Each of the $2,425 million revolving credit facilities is extendible annually at the mutual agreement of the Company and the lenders. If the facilities are not extended, the full amount of the outstanding principal is repayable on the maturity date. Borrowings under the Company's revolving term credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, US base rate or Canadian prime rate.
- 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 June 30, 2020, the non-revolving term credit facilities were fully drawn.
- During 2019, the Company entered into a $3,250 million non-revolving term credit facility to finance the acquisition of assets from Devon. The facility matures in June 2022 and is subject to annual amortization of 5% of the original balance.
- 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.

▪ Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages.

As at June 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,879 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. Including cash and cash equivalents and other liquidity, the Company had approximately $4,112 million in available liquidity. This excludes certain other dedicated credit facilities supporting letters of credit.

As at June 30, 2020, the Company had total US dollar denominated debt with a carrying amount of $17,808 million (US$13,079 million), before transaction costs and original issue discounts. This included $6,643 million (US$4,879 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$4,329 million). The fixed repayment amount of these hedging instruments is $6,529 million, resulting in a notional reduction of the carrying amount of the Company’s US dollar denominated debt by approximately $114 million to $17,694 million as at June 30, 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 $22,787 million at June 30, 2020, resulting in a debt to book capitalization ratio of 41.3% (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 is greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company’s long-term debt at June 30, 2020 are discussed in note 9 of the Company’s unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 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 June 30, 2020, 102,500 GJ/d of currently forecasted natural gas volumes were hedged using AECO fixed price swaps for July 2020 to October 2020. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2020 are discussed in note 16 of the Company's unaudited interim consolidated financial statements.

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

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 1,843	$ 5,621	$ 6,393	$ 9,274
Other long-term liabilities (2)	$ 239	$ 183	$ 410	$ 938
Interest and other financing expense (3)	$ 825	$ 770	$ 1,821	$ 4,929

(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, $202 million; one to less than two years, $158 million; two to less than five years, $389 million; and thereafter, $938 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 June 30, 2020.

Share Capital

As at June 30, 2020, there were 1,181,038,000 common shares outstanding (December 31, 2019 – 1,186,857,000 common shares) and 53,123,000 stock options outstanding. As at August 4, 2020, the Company had 1,181,038,000 common shares outstanding and 52,868,000 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.

During the first quarter of 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.

During the second quarter of 2020, no common shares were purchased under the Normal Course Issuer Bid, and the Company did not renew its Normal Course Issuer Bid.

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 June 30, 2020:

($ millions)	Remaining 2020	2021	2022	2023	2024	Thereafter
Product transportation (1)	$ 371	$ 744	$ 652	$ 737	$ 711	$ 7,959
North West Redwater Partnership service toll (2)	$ 84	$ 164	$ 161	$ 161	$ 157	$ 2,851
Offshore vessels and equipment	$ 32	$ 68	$ 9	$ —	$ —	$ —
Field equipment and power	$ 18	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 14	$ 21	$ 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. 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.

ACCOUNTING POLICIES

Government Grants

The Company has received or is eligible for government grants in response to the impact of COVID-19. These government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Grants that are intended to compensate for expenses incurred are classified as other income.

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 judgements 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 and six months ended June 30, 2020, COVID-19 had an impact on the global economy, including the oil and gas industry. In the latter half of the second quarter of 2020, business conditions and commodity prices began to improve. 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, and continues to monitor the developments in the business environment and commodity market. 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 six months ended June 30, 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.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	**Jun 30 2020**	Dec 31 2019
ASSETS			
Current assets			
Cash and cash equivalents		**$ 233**	$ 139
Accounts receivable		**1,851**	2,465
Current income taxes receivable		**306**	13
Inventory		**1,095**	1,152
Prepaids and other		**214**	174
Investments	7	**275**	490
Current portion of other long-term assets	8	**93**	54
		4,067	4,487
Exploration and evaluation assets	4	**2,525**	2,579
Property, plant and equipment	5	**65,277**	68,043
Lease assets	6	**1,654**	1,789
Other long-term assets	8	**1,222**	1,223
		$ 74,745	$ 78,121
LIABILITIES			
Current liabilities			
Accounts payable		**$ 606**	$ 816
Accrued liabilities		**2,007**	2,611
Current portion of long-term debt	9	**1,843**	2,391
Current portion of other long-term liabilities	6,10	**461**	819
		4,917	6,637
Long-term debt	9	**21,177**	18,591
Other long-term liabilities	6,10	**5,999**	7,363
Deferred income taxes		**10,319**	10,539
		42,412	43,130
SHAREHOLDERS' EQUITY			
Share capital	12	**9,521**	9,533
Retained earnings		**22,614**	25,424
Accumulated other comprehensive income	13	**198**	34
		32,333	34,991
		$ 74,745	$ 78,121

Commitments and contingencies (note 17).

Approved by the Board of Directors on August 5, 2020.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Jun 30 2020	Three Months Ended Jun 30 2019	Six Months Ended Jun 30 2020	Six Months Ended Jun 30 2019
Product sales	18	**$ 2,944**	$ 5,931	**$ 7,596**	$ 11,472
Less: royalties		**(73)**	(369)	**(225)**	(662)
Revenue		**2,871**	5,562	**7,371**	10,810
Expenses					
Production		**1,409**	1,533	**3,093**	3,063
Transportation, blending and feedstock		**759**	996	**2,191**	2,035
Depletion, depreciation and amortization	5,6	**1,403**	1,307	**2,967**	2,570
Administration		**88**	84	**196**	154
Share-based compensation	10	**23**	(7)	**(200)**	55
Asset retirement obligation accretion	10	**51**	46	**103**	90
Interest and other financing expense		**199**	197	**405**	388
Risk management activities	16	**32**	11	**(32)**	52
Foreign exchange (gain) loss		**(430)**	(217)	**492**	(456)
(Gain) loss from investments	7,8	**(55)**	62	**205**	89
		3,479	4,012	**9,420**	8,040
Earnings (loss) before taxes		**(608)**	1,550	**(2,049)**	2,770
Current income tax (recovery) expense	11	**(31)**	77	**(210)**	242
Deferred income tax recovery	11	**(267)**	(1,358)	**(247)**	(1,264)
Net earnings (loss)		**$ (310)**	$ 2,831	**$ (1,592)**	$ 3,792
Net earnings (loss) per common share					
Basic	15	**$ (0.26)**	$ 2.37	**$ (1.35)**	$ 3.17
Diluted	15	**$ (0.26)**	$ 2.36	**$ (1.35)**	$ 3.16

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended Jun 30 2020	Three Months Ended Jun 30 2019	Six Months Ended Jun 30 2020	Six Months Ended Jun 30 2019
Net earnings (loss)	**$ (310)**	$ 2,831	**$ (1,592)**	$ 3,792
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $2 million (2019 – $1 million) – three months ended; $3 million (2019 – $6 million) – six months ended	**(13)**	20	**26**	49
Reclassification to net earnings (loss), net of taxes of $nil (2019 – $2 million) – three months ended; $1 million (2019 – $3 million) – six months ended	**(2)**	10	**(9)**	(23)
	(15)	30	**17**	26
Foreign currency translation adjustment				
Translation of net investment	**(107)**	(61)	**147**	(121)
Other comprehensive income (loss), net of taxes	**(122)**	(31)	**164**	(95)
Comprehensive income (loss)	**$ (432)**	$ 2,800	**$ (1,428)**	$ 3,697

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

		Six Months Ended	
(millions of Canadian dollars, unaudited)	Note	**Jun 30 2020**	Jun 30 2019
Share capital	12		
Balance – beginning of period		**$ 9,533**	$ 9,323
Issued upon exercise of stock options		**35**	118
Previously recognized liability on stock options exercised for common shares		**9**	13
Purchase of common shares under Normal Course Issuer Bid		**(56)**	(134)
Balance – end of period		**9,521**	9,320
Retained earnings			
Balance – beginning of period		**25,424**	22,529
Net earnings (loss)		**(1,592)**	3,792
Dividends on common shares	12	**(1,003)**	(896)
Purchase of common shares under Normal Course Issuer Bid	12	**(215)**	(498)
Balance – end of period		**22,614**	24,927
Accumulated other comprehensive income	13		
Balance – beginning of period		**34**	122
Other comprehensive income (loss), net of taxes		**164**	(95)
Balance – end of period		**198**	27
Shareholders' equity		**$ 32,333**	$ 34,274

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2020**	Three Months Ended Jun 30 2019	Six Months Ended **Jun 30 2020**	Six Months Ended Jun 30 2019
Operating activities					
Net earnings (loss)		**$ (310)**	$ 2,831	**$ (1,592)**	$ 3,792
Non-cash items					
Depletion, depreciation and amortization		**1,403**	1,307	**2,967**	2,570
Share-based compensation		**23**	(7)	**(200)**	55
Asset retirement obligation accretion		**51**	46	**103**	90
Unrealized risk management loss (gain)		**1**	(16)	**(16)**	(2)
Unrealized foreign exchange (gain) loss		**(433)**	(219)	**688**	(452)
Realized foreign exchange gain on settlement of cross currency swaps		**—**	—	**(166)**	—
(Gain) loss from investments	7,8	**(53)**	68	**215**	103
Deferred income tax recovery		**(267)**	(1,358)	**(247)**	(1,264)
Other		**13**	20	**(105)**	(100)
Abandonment expenditures		**(40)**	(41)	**(129)**	(149)
Net change in non-cash working capital		**(739)**	230	**(144)**	(786)
Cash flows (used in) from operating activities		**(351)**	2,861	**1,374**	3,857
Financing activities					
Issue of bank credit facilities and commercial paper, net	9	**184**	3,273	**833**	3,908
Repayment of medium-term notes	9	**(900)**	(500)	**(900)**	(500)
Issue of US dollar debt securities	9	**1,481**	—	**1,481**	—
Proceeds on settlement of cross currency swaps	16	**—**	—	**166**	—
Payment of lease liabilities	6,10	**(61)**	(57)	**(126)**	(109)
Issue of common shares on exercise of stock options		**4**	35	**35**	118
Dividends on common shares		**(502)**	(449)	**(946)**	(852)
Purchase of common shares under Normal Course Issuer Bid	12	**—**	(391)	**(271)**	(632)
Cash flows from financing activities		**206**	1,911	**272**	1,933
Investing activities					
Net expenditures on exploration and evaluation assets		**(1)**	(37)	**(8)**	(70)
Net expenditures on property, plant and equipment		**(380)**	(830)	**(1,122)**	(1,666)
Acquisition of Devon assets		**—**	(3,412)	**—**	(3,412)
Net change in non-cash working capital		**(312)**	(185)	**(422)**	(345)
Cash flows used in investing activities		**(693)**	(4,464)	**(1,552)**	(5,493)
(Decrease) increase in cash and cash equivalents		**(838)**	308	**94**	297
Cash and cash equivalents – beginning of period		**1,071**	90	**139**	101
Cash and cash equivalents – end of period		**$ 233**	$ 398	**$ 233**	$ 398
Interest paid on long-term debt, net		**$ 174**	$ 183	**$ 387**	$ 411
Income taxes paid		**$ 31**	$ 60	**$ 72**	$ 286

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 ("NWRP"), 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 and six months ended June 30, 2020, the novel coronavirus ("COVID-19") had an impact on the global economy, including the oil and gas industry. In the latter half of the second quarter of 2020, business conditions and commodity prices began to improve. 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, and continues to monitor the developments in the business environment and commodity market. Actual results may differ from estimated amounts, and those differences may be material.

Government Grants

The Company has received or is eligible for government grants in response to the impact of COVID-19. These government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Grants that are intended to compensate for expenses incurred are classified as other income.

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 judgements 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, 2023 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.

In May 2020, the IASB issued amendments to IAS 16 “Property, Plant and Equipment” to require proceeds received from selling items produced while the entity is preparing the asset for its intended use to be recognized in net earnings, rather than as a reduction in the cost of the asset. The amendments are effective January 1, 2022 with early adoption permitted. The Company is assessing the impact of these amendments on its consolidated financial statements.

4. 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	**25**	**—**	**1**	**—**	**26**
Transfers to property, plant and equipment	**(79)**	**—**	**—**	**—**	**(79)**
Disposals/derecognitions	**(3)**	**—**	**—**	**—**	**(3)**
Foreign exchange adjustments	**—**	**—**	**2**	**—**	**2**
At June 30, 2020	**$ 2,201**	**$ —**	**$ 72**	**$ 252**	**$ 2,525**

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2019	$ 72,627	$ 7,296	$ 3,933	$ 45,016	$ 451	$ 466	$ 129,789
Additions	**479**	**43**	**41**	**539**	**3**	**13**	**1,118**
Transfers from E&E assets	**79**	**—**	**—**	**—**	**—**	**—**	**79**
Change in asset retirement obligation estimates	**(794)**	**(114)**	**(29)**	**(332)**	**(1)**	**—**	**(1,270)**
Disposals/derecognitions	**(269)**	**—**	**—**	**(150)**	**—**	**—**	**(419)**
Foreign exchange adjustments and other	**—**	**374**	**198**	**—**	**—**	**—**	**572**
At June 30, 2020	**$ 72,122**	**$ 7,599**	**$ 4,143**	**$ 45,073**	**$ 453**	**$ 479**	**$ 129,869**
Accumulated depletion and depreciation							
At December 31, 2019	$ 46,577	$ 5,712	$ 2,712	$ 6,247	$ 153	$ 345	$ 61,746
Expense	**1,769**	**150**	**58**	**839**	**7**	**13**	**2,836**
Disposals/derecognitions	**(269)**	**—**	**—**	**(150)**	**—**	**—**	**(419)**
Foreign exchange adjustments and other	**(31)**	**284**	**156**	**20**	**—**	**—**	**429**
At June 30, 2020	**$ 48,046**	**$ 6,146**	**$ 2,926**	**$ 6,956**	**$ 160**	**$ 358**	**$ 64,592**
Net book value							
- at June 30, 2020	**$ 24,076**	**$ 1,453**	**$ 1,217**	**$ 38,117**	**$ 293**	**$ 121**	**$ 65,277**
- at December 31, 2019	$ 26,050	$ 1,584	$ 1,221	$ 38,769	$ 298	$ 121	$ 68,043

The Company regularly reviews the business environment and commodity markets to assess the recoverability of the carrying value of its cash generating units ("CGUs"). As at June 30, 2020, the Company determined the carrying value of all of its CGUs to be recoverable.

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 six months ended June 30, 2020, pre-tax interest of $15 million (June 30, 2019 – $37 million) was capitalized to property, plant and equipment using a weighted average capitalization rate of 3.7% (June 30, 2019 – 4.1%).

6. 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**	**21**	**5**	**1**	**28**
Depreciation	**(61)**	**(27)**	**(29)**	**(14)**	**(131)**
Derecognitions	**(21)**	**(2)**	**(11)**	**—**	**(34)**
Foreign exchange adjustments and other	**(2)**	**(2)**	**5**	**1**	**2**
At June 30, 2020	**$ 1,083**	**$ 307**	**$ 152**	**$ 112**	**$ 1,654**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at June 30, 2020 were as follows:

	Jun 30 2020	Dec 31 2019
Lease liabilities	**$ 1,687**	$ 1,809
Less: current portion	**202**	233
	$ 1,485	$ 1,576

Total cash outflows for leases for the three months ended June 30, 2020, including payments related to short-term leases not reported as lease assets, were $230 million (three months ended June 30, 2019 – $284 million; six months ended June 30, 2020 – $549 million; six months ended June 30, 2019 – $580 million). Interest expense on leases for the three months ended June 30, 2020 was $17 million (three months ended June 30, 2019 – $19 million; six months ended June 30, 2020 – $34 million; six months ended June 30, 2019 – $34 million).

7. INVESTMENTS

As at June 30, 2020, the Company had the following investments:

	Jun 30 2020	Dec 31 2019
Investment in PrairieSky Royalty Ltd.	**$ 194**	$ 345
Investment in Inter Pipeline Ltd.	**81**	145
	$ 275	$ 490

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

	Three Months Ended		Six Months Ended	
	Jun 30 2020	Jun 30 2019	**Jun 30 2020**	Jun 30 2019
Fair value (gain) loss from investments	**$ (53)**	$ 2	**$ 215**	$ (23)
Dividend income from investments	**(2)**	(6)	**(10)**	(14)
	$ (55)	$ (4)	**$ 205**	$ (37)

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 June 30, 2020, the Company's investments in PrairieSky and Inter Pipeline were classified as current assets.

8. OTHER LONG-TERM ASSETS

		Jun 30 2020		Dec 31 2019
North West Redwater Partnership	**$**	**683**	$	652
Risk management (note 16)		**222**		290
Prepaid cost of service toll		**167**		130
Long-term inventory		**122**		121
Other		**121**		84
		1,315		1,277
Less: current portion		**93**		54
	$	**1,222**	$	1,223

The Company has a 50% equity investment in and has made subordinated debt advances of $683 million to NWRP, including accrued interest, subject to final adjustments. The subordinated debt bears interest at prime plus 6%, repayable over 10 years commencing July 2021. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that targets 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, an agent of the Government of Alberta, under a 30-year fee-for-service tolling agreement.

The unrecognized share of equity losses from NWRP for the three months ended June 30, 2020 was $23 million (six months ended June 30, 2020 – unrecognized equity loss of $116 million). As at June 30, 2020, the cumulative unrecognized share of losses from NWRP was $175 million (December 31, 2019 – $59 million).

On June 1, 2020 the refinery achieved the Commercial Operation Date ("COD"), pursuant to terms of the tolling agreement. Following COD, the Company is unconditionally obligated to pay its 25% pro rata share of the debt tolls over the 30-year tolling period (note 17). Subsequent to COD, sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment.

9. LONG-TERM DEBT

	Jun 30 2020	Dec 31 2019
Canadian dollar denominated debt, unsecured		
Bank credit facilities	**$ 1,923**	$ 1,688
Medium-term notes	**3,400**	4,300
	5,323	5,988
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2020 – US$3,829 million; December 31, 2019 – US$3,745 million)	**5,213**	4,855
Commercial paper (June 30, 2020 – US$500 million; December 31,2019 – US$254 million)	**681**	329
US dollar debt securities (June 30, 2020 – US$8,750 million; December 31, 2019 – US$7,650 million)	**11,914**	9,918
	17,808	15,102
Long-term debt before transaction costs and original issue discounts, net	**23,131**	21,090
Less: original issue discounts, net (1)	**19**	17
transaction costs (1) (2)	**92**	91
	23,020	20,982
Less: current portion of commercial paper	**681**	329
current portion of other long-term debt (1) (2)	**1,162**	2,062
	$ 21,177	$ 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 six months ended June 30, 2020, the Company reported an unrealized foreign exchange loss of $610 million (June 30, 2019 – gain of $511 million) on its US dollar denominated debt, excluding the impact of hedging.

Bank Credit Facilities and Commercial Paper

As at June 30, 2020, the Company had in place revolving bank credit facilities of $4,958 million, of which $3,879 million was available. Additionally, the Company had in place fully drawn term credit facilities of $6,738 million. Details of these facilities are described below. This excludes certain other dedicated credit facilities supporting letters of credit.

- a $100 million demand credit facility;
- a $1,000 million non-revolving term credit facility maturing February 2022;
- a $2,425 million revolving syndicated credit facility maturing June 2022;
- a $3,088 million non-revolving term credit facility maturing June 2022;
- a $2,650 million non-revolving term credit facility maturing February 2023;
- a $2,425 million revolving syndicated credit facility maturing June 2023; and
- a £5 million demand credit facility related to the Company’s North Sea operations.

During the second quarter of 2020, the $750 million non-revolving term credit facility, originally due February 2021, was extended to February 2022 and increased to $1,000 million.

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 June 30, 2020, the non-revolving term credit facilities were fully drawn.

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 June 30, 2020 was 1.4% (June 30, 2019 – 2.6%), and on total long-term debt outstanding for the six months ended June 30, 2020 was 3.7% (June 30, 2019 – 4.1%).

As at June 30, 2020, letters of credit and guarantees aggregating to $465 million were outstanding.

Medium-Term Notes

During the second quarter of 2020, the Company repaid $900 million of 2.05% 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

During the second quarter of 2020, the Company issued US$600 million of 2.05% notes due July 2025 and US$500 million of 2.95% notes due July 2030.

After issuing these securities, the Company had US$1,900 million remaining on its 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.

10. OTHER LONG-TERM LIABILITIES

	Jun 30 2020	Dec 31 2019
Asset retirement obligations	**$ 4,532**	$ 5,771
Lease liabilities (note 6)	**1,687**	1,809
Share-based compensation	**54**	297
Deferred purchase consideration (1)	**71**	95
Risk management (note 16)	**12**	112
Other	**104**	98
	6,460	8,182
Less: current portion	**461**	819
	$ 5,999	$ 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:

	Jun 30 2020	Dec 31 2019
Balance – beginning of period	**$ 5,771**	$ 3,886
Liabilities incurred	**2**	15
Liabilities (disposed) acquired, net	**(1)**	198
Liabilities settled	**(129)**	(296)
Asset retirement obligation accretion	**103**	190
Change in discount rates	**(1,270)**	1,412
Foreign exchange adjustments	**56**	(46)
Revision of cost, inflation rates and timing estimates	**—**	412
Balance – end of period	**4,532**	5,771
Less: current portion	**154**	208
	$ 4,378	$ 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.

	Jun 30 2020	Dec 31 2019
Balance – beginning of period	**$ 297**	$ 124
Share-based compensation (recovery) expense	**(200)**	223
Cash payment for stock options surrendered and PSUs vested	**(37)**	(2)
Transferred to common shares	**(9)**	(53)
Charged to Oil Sands Mining and Upgrading, net	**3**	5
Balance – end of period	**54**	297
Less: current portion	**39**	227
	$ 15	$ 70

Included within share-based compensation liability as at June 30, 2020 was $22 million related to PSUs granted to certain executive employees (December 31, 2019 – $62 million).

11. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended Jun 30 2020	Three Months Ended Jun 30 2019	Six Months Ended Jun 30 2020	Six Months Ended Jun 30 2019
Current corporate income tax – North America	**$ (34)**	$ 78	**$ (228)**	$ 241
Current corporate income tax – North Sea	**1**	28	**10**	57
Current corporate income tax – Offshore Africa	**2**	11	**6**	23
Current PRT [1] – North Sea	**—**	(43)	**—**	(85)
Other taxes	**—**	3	**2**	6
Current income tax	**(31)**	77	**(210)**	242
Deferred corporate income tax	**(267)**	(1,359)	**(247)**	(1,265)
Deferred PRT [1] – North Sea	**—**	1	**—**	1
Deferred income tax	**(267)**	(1,358)	**(247)**	(1,264)
Income tax	**$ (298)**	$ (1,281)	**$ (457)**	$ (1,022)

(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.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued common shares	Six Months Ended Jun 30, 2020 Number of shares (thousands)		Amount
Balance – beginning of period	**1,186,857**	**$**	**9,533**
Issued upon exercise of stock options	**1,151**		**35**
Previously recognized liability on stock options exercised for common shares	**—**		**9**
Purchase of common shares under Normal Course Issuer Bid	**(6,970)**		**(56)**
Balance – end of period	**1,181,038**	**$**	**9,521**

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.

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.

During the first quarter of 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.

During the second quarter of 2020, no common shares were purchased under the Normal Course Issuer Bid, and the Company did not renew its Normal Course Issuer Bid.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2020:

	Six Months Ended Jun 30, 2020 Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of period	**47,646**	**$**	**38.04**
Granted	**11,390**	**$**	**33.18**
Exercised for common shares	**(1,151)**	**$**	**30.96**
Surrendered for cash settlement	**(315)**	**$**	**34.04**
Forfeited	**(4,447)**	**$**	**39.86**
Outstanding – end of period	**53,123**	**$**	**37.01**
Exercisable – end of period	**15,910**	**$**	**38.62**

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

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Jun 30 2020	Jun 30 2019
Derivative financial instruments designated as cash flow hedges	$ 88	$ 39
Foreign currency translation adjustment	110	(12)
	$ 198	$ 27

14. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At June 30, 2020, the ratio was within the target range at 41.3%.

Readers are cautioned that the debt to book capitalization ratio is not defined by IFRS and this financial measure may not be comparable to similar measures presented by other companies. Further, there are no assurances that the Company will continue to use this measure to monitor capital or will not alter the method of calculation of this measure in the future.

	Jun 30 2020	Dec 31 2019
Long-term debt, net [1]	$ 22,787	$ 20,843
Total shareholders' equity	$ 32,333	$ 34,991
Debt to book capitalization	41.3%	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 June 30, 2020, the Company was in compliance with this covenant.

15. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2020	Jun 30 2019	Jun 30 2020	Jun 30 2019
Weighted average common shares outstanding – basic (thousands of shares)	1,180,925	1,193,185	1,182,031	1,197,045
Effect of dilutive stock options (thousands of shares)	—	2,690	—	2,503
Weighted average common shares outstanding – diluted (thousands of shares)	1,180,925	1,195,875	1,182,031	1,199,548
Net earnings (loss)	$ (310)	$ 2,831	$ (1,592)	$ 3,792
Net earnings (loss) per common share – basic	$ (0.26)	$ 2.37	$ (1.35)	$ 3.17
– diluted	$ (0.26)	$ 2.36	$ (1.35)	$ 3.16

16. FINANCIAL INSTRUMENTS

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

	Jun 30, 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	**$ 1,851**	**$ —**	**$ —**	**$ —**	**$ 1,851**
Investments	**—**	**275**	**—**	**—**	**275**
Other long-term assets	**683**	**—**	**222**	**—**	**905**
Accounts payable	**—**	**—**	**—**	**(606)**	**(606)**
Accrued liabilities	**—**	**—**	**—**	**(2,007)**	**(2,007)**
Other long-term liabilities (1)	**—**	**(5)**	**(7)**	**(1,758)**	**(1,770)**
Long-term debt (2)	**—**	**—**	**—**	**(23,020)**	**(23,020)**
	$ 2,534	**$ 270**	**$ 215**	**$ (27,391)**	**$ (24,372)**

	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 $1,687 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:

	Jun 30, 2020			
	Carrying amount	**Fair value**		
Asset (liability) (1) (2)		**Level 1**	**Level 2**	**Level 3** (4) (5)
Investments (3)	**$ 275**	**$ 275**	**$ —**	**$ —**
Other long-term assets	**$ 905**	**$ —**	**$ 222**	**$ 683**
Other long-term liabilities	**$ (83)**	**$ —**	**$ (12)**	**$ (71)**
Fixed rate long-term debt (6) (7)	**$ (15,203)**	**$ (16,606)**	**$ —**	**$ —**

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 NWRP 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)		**Jun 30 2020**		Dec 31 2019
Derivatives held for trading				
Natural gas AECO fixed price swaps	**$**	**(4)**	$	(3)
Foreign currency forward contracts		**(1)**		(10)
Natural gas AECO basis swaps		**—**		(8)
Cash flow hedges				
Foreign currency forward contracts		**9**		(91)
Cross currency swaps		**206**		290
	$	**210**	$	178
Included within:				
Current portion of other long-term assets	**$**	**21**	$	8
Current portion of other long-term liabilities		**(12)**		(112)
Other long-term assets		**201**		282
	$	**210**	$	178

For the six months ended June 30, 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 (liability) were recognized in the financial statements as follows:

Asset (liability)	Jun 30 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	16	(13)
Foreign exchange	(3)	(231)
Other comprehensive income	19	66
Balance – end of period	210	178
Less: current portion	9	(104)
	$ 201	$ 282

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

	Three Months Ended		Six Months Ended	
	Jun 30 2020	Jun 30 2019	Jun 30 2020	Jun 30 2019
Net realized risk management loss (gain)	$ 31	$ 27	$ (16)	$ 54
Net unrealized risk management loss (gain)	1	(16)	(16)	(2)
	$ 32	$ 11	$ (32)	$ 52

Financial Risk Factors

a) Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. The Company's market risk is comprised of commodity price risk, interest rate risk, and foreign currency exchange risk.

Commodity price risk management

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production and with natural gas purchases.

At June 30, 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	Jul 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 June 30, 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 contract requires the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based.

At June 30, 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	Jul 2020	–	Mar 2038	US$550	1.170	6.25 %	5.76 %

The cross currency swap derivative financial instrument was designated as a hedge at June 30, 2020 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at June 30, 2020, the Company had US$5,314 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$4,329 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 June 30, 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 June 30, 2020, the Company had net risk management assets of $216 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	$	606	$	—	$	—	$	—
Accrued liabilities	$	2,007	$	—	$	—	$	—
Long-term debt (1)	$	1,843	$	5,621	$	6,393	$	9,274
Other long-term liabilities (2)	$	239	$	183	$	410	$	938
Interest and other financing expense (3)	$	825	$	770	$	1,821	$	4,929

(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, $202 million; one to less than two years, $158 million; two to less than five years, $389 million; and thereafter $938 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 June 30, 2020.

17. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2020:

	Remaining 2020	2021	2022	2023	2024	Thereafter
Product transportation (1)	$ 371	$ 744	$ 652	$ 737	$ 711	$ 7,959
North West Redwater Partnership service toll (2)	$ 84	$ 164	$ 161	$ 161	$ 157	$ 2,851
Offshore vessels and equipment	$ 32	$ 68	$ 9	$ —	$ —	$ —
Field equipment and power	$ 18	$ 21	$ 20	$ 21	$ 20	$ 249
Other	$ 14	$ 21	$ 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. Included in the cost of service tolls is $1,222 million of interest payable over the 30-year tolling period (note 8).

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

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

18. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
(millions of Canadian dollars, unaudited)	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales																
Crude oil and NGLs	**974**	2,297	**2,824**	4,136	**99**	211	**232**	345	**22**	203	**106**	312	**1,095**	2,711	**3,162**	4,793
Natural gas	**256**	249	**531**	624	**2**	11	**10**	36	**12**	18	**20**	36	**270**	278	**561**	696
Other income and revenue [1]	**21**	3	**11**	5	**2**	2	**3**	2	**1**	2	**3**	3	**24**	7	**17**	10
Total segmented product sales	**1,251**	2,549	**3,366**	4,765	**103**	224	**245**	383	**35**	223	**129**	351	**1,389**	2,996	**3,740**	5,499
Less: royalties	**(65)**	(231)	**(179)**	(424)	**(1)**	(1)	**(1)**	(1)	**(1)**	(10)	**(5)**	(21)	**(67)**	(242)	**(185)**	(446)
Segmented revenue	**1,186**	2,318	**3,187**	4,341	**102**	223	**244**	382	**34**	213	**124**	330	**1,322**	2,754	**3,555**	5,053
Segmented expenses																
Production	**585**	571	**1,294**	1,173	**67**	100	**161**	167	**13**	24	**35**	42	**665**	695	**1,490**	1,382
Transportation, blending and feedstock	**546**	576	**1,616**	1,100	**4**	4	**11**	10	**—**	—	**—**	1	**550**	580	**1,627**	1,111
Depletion, depreciation and amortization	**871**	790	**1,826**	1,533	**76**	73	**175**	127	**27**	66	**68**	112	**974**	929	**2,069**	1,772
Asset retirement obligation accretion	**23**	21	**50**	41	**8**	8	**15**	15	**2**	2	**3**	3	**33**	31	**68**	59
Risk management activities (commodity derivatives)	**4**	(3)	**6**	29	**—**	—	**—**	—	**—**	—	**—**	—	**4**	(3)	**6**	29
Equity loss from investments	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,029**	1,955	**4,792**	3,876	**155**	185	**362**	319	**42**	92	**106**	158	**2,226**	2,232	**5,260**	4,353
Segmented earnings (loss) before the following	**(843)**	363	**(1,605)**	465	**(53)**	38	**(118)**	63	**(8)**	121	**18**	172	**(904)**	522	**(1,705)**	700
Non–segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management activities (other)																
Foreign exchange (gain) loss																
(Gain) loss from investments																
Total non–segmented expenses																
Earnings (loss) before taxes																
Current income tax (recovery) expense																
Deferred income tax recovery																
Net earnings (loss)																

(millions of Canadian dollars, unaudited)	**Oil Sands Mining and Upgrading**				**Midstream and Refining**				**Inter–segment elimination and other**				**Total**			
	Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30		Three Months Ended Jun 30		Six Months Ended Jun 30	
	2020	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Segmented product sales																
Crude oil and NGLs [(2)]	**1,343**	2,736	**3,547**	5,590	**20**	20	**41**	41	**4**	130	**35**	255	**2,462**	5,597	**6,785**	10,679
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**37**	46	**83**	84	**307**	324	**644**	780
Other income and revenue [(1)]	**103**	3	**100**	3	**25**	—	**25**	—	**23**	—	**25**	—	**175**	10	**167**	13
Total segmented product sales	**1,446**	2,739	**3,647**	5,593	**45**	20	**66**	41	**64**	176	**143**	339	**2,944**	5,931	**7,596**	11,472
Less: royalties	**(6)**	(127)	**(40)**	(216)	**—**	—	**—**	—	**—**	—	**—**	—	**(73)**	(369)	**(225)**	(662)
Segmented revenue	**1,440**	2,612	**3,607**	5,377	**45**	20	**66**	41	**64**	176	**143**	339	**2,871**	5,562	**7,371**	10,810
Segmented expenses																
Production	**730**	814	**1,539**	1,636	**29**	5	**35**	11	**(15)**	19	**29**	34	**1,409**	1,533	**3,093**	3,063
Transportation, blending and feedstock [(2)]	**183**	259	**453**	619	**22**	—	**22**	—	**4**	157	**89**	305	**759**	996	**2,191**	2,035
Depletion, depreciation and amortization	**451**	374	**891**	791	**3**	4	**7**	7	**(25)**	—	**—**	—	**1,403**	1,307	**2,967**	2,570
Asset retirement obligation accretion	**18**	15	**35**	31	**—**	—	**—**	—	**—**	—	**—**	—	**51**	46	**103**	90
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**4**	(3)	**6**	29
Equity loss from investments	**—**	—	**—**	—	**—**	66	**—**	126	**—**	—	**—**	—	**—**	66	**—**	126
Total segmented expenses	**1,382**	1,462	**2,918**	3,077	**54**	75	**64**	144	**(36)**	176	**118**	339	**3,626**	3,945	**8,360**	7,913
Segmented earnings (loss) before the following	**58**	1,150	**689**	2,300	**(9)**	(55)	**2**	(103)	**100**	—	**25**	—	**(755)**	1,617	**(989)**	2,897
Non–segmented expenses																
Administration													**88**	84	**196**	154
Share-based compensation													**23**	(7)	**(200)**	55
Interest and other financing expense													**199**	197	**405**	388
Risk management activities (other)													**28**	14	**(38)**	23
Foreign exchange (gain) loss													**(430)**	(217)	**492**	(456)
(Gain) loss from investments													**(55)**	(4)	**205**	(37)
Total non–segmented expenses													**(147)**	67	**1,060**	127
Earnings (loss) before taxes													**(608)**	1,550	**(2,049)**	2,770
Current income tax (recovery) expense													**(31)**	77	**(210)**	242
Deferred income tax recovery													**(267)**	(1,358)	**(247)**	(1,264)
Net earnings (loss)													**(310)**	2,831	**(1,592)**	3,792

(1) Includes other income, the sale of diesel and other refined products, and *recoveries associated with the joint operation partners' share of the costs of lease contracts.*
(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)

	Six Months Ended					
	Jun 30, 2020			Jun 30, 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 (3)	**$ 7**	**$ (64)**	**$ (57)**	$ 126	$ (149)	$ (23)
Offshore Africa	**1**	**—**	**1**	35	—	35
	$ 8	**$ (64)**	**$ (56)**	$ 161	$ (149)	$ 12
Property, plant and equipment						
Exploration and Production						
North America (3)	**$ 483**	**$ (988)**	**$ (505)**	$ 4,010	$ 1,025	$ 5,035
North Sea	**43**	**(114)**	**(71)**	78	105	183
Offshore Africa (4)	**41**	**(29)**	**12**	105	(1,490)	(1,385)
	567	**(1,131)**	**(564)**	4,193	(360)	3,833
Oil Sands Mining and Upgrading (5)	**539**	**(482)**	**57**	576	169	745
Midstream and Refining	**3**	**(1)**	**2**	5	—	5
Head office	**13**	**—**	**13**	18	(3)	15
	$ 1,122	**$ (1,614)**	**$ (492)**	$ 4,792	$ (194)	$ 4,598

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

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

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

(4) 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.

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

Segmented Assets

	Jun 30 2020	Dec 31 2019
Exploration and Production		
North America	**$ 28,749**	$ 30,963
North Sea	**1,605**	1,948
Offshore Africa	**1,529**	1,529
Other	**65**	30
Oil Sands Mining and Upgrading	**41,197**	42,006
Midstream and Refining	**1,375**	1,418
Head office	**225**	227
	$ 74,745	$ 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 June 30, 2020:	
Interest coverage (times)	
Net earnings [(1)]	1.1x
Adjusted funds flow [(2)]	9.0x

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

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

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Corporate Information

Board of Directors

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Christopher L. Fong

Ambassador Gordon D. Giffin

Wilfred A. Gobert

Steve W. Laut

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

David A. Tuer

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Officers

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Executive Chairman

Tim S. McKay
President

Darren M. Fichter
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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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