Canadian Natural

SECOND QUARTER REPORT

SIX MONTHS ENDED JUNE 30, 2021 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2021 SECOND QUARTER RESULTS

Commenting on the Company's second quarter 2021 results, Tim McKay, President of Canadian Natural stated "Canadian Natural is in a strong position as our vast and diverse asset base delivered strong operational and financial results in Q2/21, as we achieved production volumes of approximately 1,142 MBOE/d in the quarter, notwithstanding the planned turnaround at our Oil Sands Mining and Upgrading operations.

Canadian Natural's long life low decline asset base generated significant free cash flow in the quarter maximizing value for our shareholders, as we balanced free cash flow to our four pillars of capital allocation; balance sheet strength, returns to shareholders, economic resource development and opportunistic acquisitions. In the first two quarters of 2021 we have reduced net debt by approximately $3.1 billion, returned approximately $1.3 billion to our shareholders through dividends and share repurchases, maintained capital discipline and executed on various opportunistic and strategic transactions which add long term value.

With the increased positive outlook for commodity prices for the remainder of 2021, we have increased our 2021 capital budget by $275 million to $3.48 billion as we undertake lead activities for future growth opportunities. The increase includes $120 million for conventional and unconventional assets, $110 million for long life low decline assets and $45 million in additional well abandonment activities. These increased investments are being financed out of the repayment of the North West Redwater Partnership ("NWRP") subordinated debt. This additional capital, along with strong operating performance from our existing 2021 drilling program, now has us targeting natural gas production above our previous guided production range and corporate production on a BOE basis above the mid-point of our previous guided production range for the 2021 year.

As previously announced, the Oil Sands Pathways initiative to achieve net zero greenhouse gas emissions by 2050 is an unprecedented initiative by the Canadian energy industry, by which Canadian Natural and our industry partners will strengthen our leading environmental, social and governance ("ESG") performance, while delivering meaningful emissions reductions and balancing sustainable economic development. Collaboration with the federal and Alberta governments on this initiative will be critical for Canada to achieve its climate goals."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "Canadian Natural's robust business model and world class assets delivered strong adjusted funds flow in Q2/21 of approximately $3.05 billion, resulting in approximately $1.5 billion in free cash flow after dividends and capital expenditures, excluding acquisitions.

In Q2/21, net debt was reduced by approximately $1.7 billion as we repaid and retired the remaining $2.125 billion on our non-revolving term loan originally maturing in June 2022. In addition, subsequent to quarter end, we exercised the par call option on our US$0.5 billion November 2021 public bond, allowing us to repay the bond early in August 2021, capturing interest cost savings and further retiring absolute debt.

Annual 2021 WTI strip pricing has continued to strengthen from Q2/21 quarter end and using an annual average of US$66/bbl WTI, our 2021 targeted free cash flow increases significantly to a range of $7.2 billion to $7.7 billion, after dividends and net capital expenditures, excluding acquisitions. As a result of this strong free cash flow and increasing balance sheet strength achieved through 2021, the Board of Directors has revised its share repurchase policy effective July 1, 2021 and has authorized management to increase returns to shareholders through incremental share repurchases of approximately 1% of shares outstanding, or approximately 11 million shares, per quarter. Additionally, the new policy provides that once the Company reaches an absolute debt level of $15 billion, currently targeted to occur in Q4/21, 50% of free cash flow is targeted to be allocated to share repurchases under the Company's Normal Course Issuer Bid (“NCIB”), with the remaining 50% allocated to further strengthening of the Company's balance sheet."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended **Jun 30 2021**	 Mar 31 2021	 June 30 2020	Six Months Ended **June 30 2021**	 June 30 2020
Net earnings (loss)	**$ 1,551**	$ 1,377	$ (310)	**$ 2,928**	$ (1,592)
Per common share – basic	**$ 1.31**	$ 1.16	$ (0.26)	**$ 2.47**	$ (1.35)
– diluted	**$ 1.30**	$ 1.16	$ (0.26)	**$ 2.46**	$ (1.35)
Adjusted net earnings (loss) from operations [(1)]	**$ 1,480**	$ 1,219	$ (772)	**$ 2,699**	$ (1,067)
Per common share – basic	**$ 1.25**	$ 1.03	$ (0.65)	**$ 2.28**	$ (0.90)
– diluted	**$ 1.24**	$ 1.03	$ (0.65)	**$ 2.27**	$ (0.90)
Cash flows from (used in) operating activities	**$ 2,940**	$ 2,536	$ (351)	**$ 5,476**	$ 1,374
Adjusted funds flow [(2)]	**$ 3,049**	$ 2,712	$ 415	**$ 5,761**	$ 1,752
Per common share – basic	**$ 2.57**	$ 2.29	$ 0.35	**$ 4.86**	$ 1.48
– diluted	**$ 2.56**	$ 2.28	$ 0.35	**$ 4.85**	$ 1.48
Cash flows used in investing activities	**$ 719**	$ 648	$ 693	**$ 1,367**	$ 1,552
Net capital expenditures, excluding net acquisition costs [(3)]	**$ 957**	$ 808	$ 421	**$ 1,765**	$ 1,259
Net capital expenditures, including net acquisition costs [(3)]	**$ 1,285**	$ 808	$ 421	**$ 2,093**	$ 1,259
Daily production, before royalties					
Natural gas (MMcf/d)	**1,614**	1,598	1,462	**1,606**	1,451
Crude oil and NGLs (bbl/d)	**872,718**	979,352	921,895	**925,741**	930,286
Equivalent production (BOE/d) [(4)]	**1,141,739**	1,245,703	1,165,487	**1,193,434**	1,172,120

Footnotes 1 through 3 describe non-GAAP financial measures that the Company considers key in evaluating its performance. Derivations of these measures are discussed in the "Advisory" section of this press release.

(1) Adjusted net earnings (loss) from operations demonstrates the Company's ability to generate after-tax operating earnings from its core business areas.

(2) Adjusted funds flow demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

(3) Net capital expenditures provides an understanding of the Company's capital spending activities in comparison to the Company's annual capital budget.

(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, or to compare the value ratio using current crude oil and natural gas prices 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.

- Net earnings of $1,551 million and adjusted net earnings from operations of $1,480 million were realized in Q2/21, a significant increase from Q2/20 levels, primarily as a result of higher realized pricing and effective and efficient operations.
- Cash flows from operating activities were $2,940 million in Q2/21.
- The strength of our assets, supported by safe, effective and efficient operations demonstrate our ability to generate significant and sustainable free cash flow over the long-term, making Canadian Natural's business unique, robust and sustainable.
  - As a result, Canadian Natural generated strong quarterly adjusted funds flow of $3,049 million in Q2/21, an increase of $2,634 million from Q2/20 levels, primarily as a result of higher realized pricing and effective and efficient operations.

- Year to date in 2021 to the end of July, Canadian Natural has delivered effective and efficient operations and by remaining nimble has executed on a number of strategic initiatives that have resulted in increasing free cash flow generation and long term shareholder value. These strategic initiatives are outlined below:
  - On June 30, 2021, the Company and the equity partners together with the toll payers, agreed to optimize the structure of NWRP, to better align the commercial interests of the equity partners and the toll payers. Under this Optimization Transaction, NWRP repaid the Company's subordinated debt advance of $555 million and the Company received a $400 million distribution from NWRP.
  - The Company owns approximately 6.4 million shares of Inter Pipeline Ltd. ("IPL"), which is currently subject to a third-party offer to purchase, with the current value of these shares being approximately $130 million to the Company, provided that all conditions of the third-party offer for IPL shares are satisfied.
  - As a result of these strategic initiatives Canadian Natural will realize cash proceeds of approximately $1,085 million, which will be allocated to our four pillars of capital allocation; balance sheet strength, returns to shareholders, economic resource development and opportunistic acquisitions. In this regard the Company has and will utilize a portion of these proceeds as follows:
    - Year to date, the Company has completed three opportunistic acquisitions. The first two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d (consisting of 63 MMcf/d and 600 bbl/d of NGLs), approximately 107,000 acres of Montney lands, and related processing infrastructure with approximately 140 MMcf/d of capacity. These two acquisitions build on the Company's expansive natural gas operations in northeastern British Columbia increasing our total Montney lands to approximately 1.3 million acres. The third acquisition consisted of a 5% net carried interest on an existing Canadian Natural oil sands lease, from which all of our Horizon production is derived. Total cash consideration paid for these acquisitions was approximately $450 million and our 2021 capital expenditures will be increased by this amount.
    - To further invest in value adding opportunities on our vast asset base, the Company plans to increase its 2021 capital budget by $275 million, excluding acquisitions, to approximately $3.48 billion, including approximate additions of $120 million related to conventional and unconventional assets, $110 million related to long life low decline assets and additional $45 million related to abandonment and reclamation activities. The additional activities in the second half of 2021 are as follows:
      - Additional conventional and unconventional capital of approximately $120 million primarily relates to additional drilling of 78 crude oil wells and development activities, with a targeted capital efficiency from these expenditures of approximately $8,400 per flowing BOE and a 2021 exit rate of approximately 14,000 BOE/d.
      - Additional long life low decline asset capital of approximately $110 million, consisting of approximately $35 million for construction of three new pads at Primrose, two new pads at Kirby North and two new pads at Kirby South, which will support production additions in 2022 and beyond. At Horizon, the additional capital of approximately $75 million is primarily related to additional scopes completed and the extended turnaround in Q2/21.
      - Our area based abandonment programs have been highly cost effective and as a result incremental capital is being allocated to complete an additional 800 well abandonments over our initial 2021 target of 2,500, as we continue to prudently manage our liabilities and environmental footprint.
      - These additional expenditures will result in an estimated increase of 1,500 jobs across Alberta, British Columbia and Saskatchewan.
  - These additional expenditures, effective and efficient operations, strong operational and drilling performance, development activities, and acquisitions have resulted in increased annual corporate production.
    - Corporate annual natural gas production is targeted to be above the top end of the previously issued range in 2021, with annual production levels now targeted between 1,680 MMcf/d to 1,720 MMcf/d, with targeted year end exit volumes in excess of 1,800 MMcf/d.
    - Corporate annual liquids production is targeted to be above the mid-point of the previously issued range in 2021, with annual production levels now targeted between 940 Mbbl/d to 980 Mbbl/d.
    - Corporate annual production is targeted to be above the mid-point of the previously issued range in 2021, with annual production levels now targeted between 1,220 MBOE/d to 1,267 MBOE/d.

- Annual 2021 free cash flow is targeted to be robust at a range of $7.2 billion to $7.7 billion using an annual average WTI of US$66/bbl, after dividends and budgeted capital expenditures, excluding net acquisitions.
  - Free cash flow generation has been significant in 2021 and the Company's balance sheet continues to strengthen, providing the Board of Directors the confidence to approve a more defined free cash flow allocation policy in accordance with the Company's four pillars of capital allocation. Effective July 1, 2021 under the new policy, the Company targets to allocate free cash flow as follows:
    - Increased returns to shareholders through incremental share repurchases of approximately 1% of common shares outstanding or approximately 11 million shares per quarter.
    - Once the Company reaches $15.0 billion in absolute debt, currently targeted to occur in Q4/21, 50% of free cash flow is targeted to be allocated to share repurchases under the Company's NCIB, with the remaining 50% allocated to further strengthening of the Company's balance sheet.
- In Q2/21, reflecting the strength of our effective and efficient operations and our high quality, long life low decline asset base, Canadian Natural generated robust quarterly free cash flow of $1,535 million, after dividend payments of $557 million and net capital expenditures of $957 million, excluding acquisitions.
- Canadian Natural executed on our commitment to further strengthen our balance sheet with strong financial results in Q2/21, reducing net debt by approximately $1.7 billion from Q1/21 levels. Net debt has decreased by approximately $3.1 billion in the first two quarters of 2021.
- In Q2/21 the Company fully repaid and retired the remaining outstanding balance on its $2,125 million non-revolving term loan. The facility was originally due in June 2022.
- Subsequent to quarter end the Company exercised a 90-day par call option on its US$500 million 3.45% notes originally due November 15, 2021 with repayment to occur on August 16, 2021.
- Returns to shareholders year to date in 2021 have been significant, as Canadian Natural has returned approximately $1.5 billion by way of dividends and share repurchases up to and including August 4, 2021.
  - In March 2021, the Company declared a quarterly dividend of $0.47 per share, an increase of 11% from the previous level of $0.425 per share, marking 2021 as the Company's 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and the robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
  - Subsequent to quarter end the Company declared a quarterly dividend of $0.47 per share, payable on October 5, 2021.
  - In March 2021, the Board of Directors authorized management to repurchase shares under a NCIB to approximately offset options exercised throughout the coming year, in order to minimize or eliminate dilution to shareholders.
    - Share repurchases for cancellation in 2021 up to and including August 4, 2021 total 11,044,400 common shares at a weighted average price of $42.00.
- In Q2/21 the Company continued its focus on safe, effective and efficient operations averaging quarterly production volumes of 1,141,739 BOE/d, decreases of 2% and 8% from Q2/20 and Q1/21 levels respectively. The decreases from prior periods are primarily as a result of the timing of the planned turnaround at our Oil Sands Mining and Upgrading operations, in particular at Horizon and de-coking at the Scotford Upgrader ("Scotford") completed in the quarter.
  - Corporate natural gas production averaged 1,614 MMcf/d in Q2/21, an increase of 10% from Q2/20 levels and comparable with Q1/21 levels. The increase from Q2/20 was primarily as a result of acquired production in Q4/20 and strong drilling results, partially offset by natural field declines and the temporary full quarter shutdown of the Pine River Gas Plant, which resumed operations on July 24, 2021, restoring production of approximately 100 MMcf/d.
    - Corporate natural gas operating costs in Q2/21 averaged $1.19/Mcf, an increase of 3% from Q2/20 levels and a decrease of 6% from Q1/21 levels. The increase from Q2/20 was primarily due the increase in electricity costs. The decrease from Q1/21 primarily reflects the impact of seasonality.
  - Quarterly liquids production volumes averaged 872,718 bbl/d in Q2/21, decreases of 5% and 11% from Q2/20 and Q1/21 levels respectively, primarily as a result of the timing of the planned turnaround at Horizon and de-coking at Scotford completed in the quarter.

- Canadian Natural's North America E&P liquids production, including thermal in situ was strong in Q2/21 averaging 478,314 bbl/d, an increase of 16% from Q2/20 levels and comparable with Q1/21 levels.
  - North American E&P liquids, including thermal in situ, operating costs averaged $12.82/bbl (US$10.44/bbl) in Q2/21, an increase of 10% from Q2/20 levels and comparable with Q1/21 levels of $12.80/bbl. The increase in operating costs from Q2/20 was primarily due to increased energy costs.
- Canadian Natural's thermal in situ production averaged 258,551 bbl/d in Q2/21, an increase of 21% over Q2/20 levels and a decrease of 3% from Q1/21 levels.
  - Thermal in situ assets operating costs averaged $11.78/bbl (US$9.59/bbl) in Q2/21, increases of 16% and 3% from Q2/20 and Q1/21 levels respectively. The increase in operating costs from Q2/20 was primarily due to increased energy costs and the increase from Q1/21 was primarily as a result of lower volumes in Q2/21 from Q1/21 levels.
- The Company's world class Oil Sands Mining and Upgrading assets averaged quarterly production of 361,707 bbl/d of Synthetic Crude Oil ("SCO") in Q2/21, decreases of 22% and 23% from Q2/20 and Q1/21 levels respectively due to the timing of the planned turnaround at Horizon and de-coking at Scotford, which were both completed in the second quarter of 2021.
  - The Company's focus on continuous improvement initiatives delivered high utilization and reliability at the Company's Oil Sands Mining and Upgrading assets. As a result, record monthly SCO production of approximately 495,100 bbl/d was achieved in June 2021, an increase from the previous record of approximately 490,800 bbl/d of SCO achieved in December 2020.

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 SCO (herein collectively referred to as "crude oil") and natural gas and NGLs. This balance provides optionality for capital investments, maximizing value for the Company's shareholders.

Underpinning this asset base is the Company's long life low decline production, representing approximately 77% of our total liquids production in Q2/21, the majority of which is zero decline high value SCO production from the Company's world class Oil Sands Mining and Upgrading assets. The remaining balance of long life low decline production comes from Canadian Natural's top tier thermal in situ oil sands operations and the Company's Pelican Lake heavy crude oil assets. The combination of these long life low decline assets, low reserves replacement costs, and effective and efficient operations, results in substantial and sustainable adjusted funds flow throughout the commodity price cycle.

In addition, 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, in the right economic conditions, provide excellent returns and maximizes value for our 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			
	2021		2020	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil	**73**	**71**	43	37
Natural gas	**38**	**31**	13	12
Dry	**—**	**—**	—	—
Subtotal	**111**	**102**	56	49
Stratigraphic test / service wells	**396**	**329**	424	371
Total	**507**	**431**	480	420
Success rate (excluding stratigraphic test / service wells)		**100%**		100%

- The Company's total crude oil and natural gas drilling program of 102 net wells for the six months ended June 30, 2021, excluding stratigraphic/service wells, represents an increase of 53 net wells from the same period in 2020.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	June 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Crude oil and NGLs production (bbl/d)	**219,763**	211,206	200,699	**215,508**	214,637
Net wells targeting crude oil	**22**	39	2	**61**	30
Net successful wells drilled	**22**	39	2	**61**	30
Success rate	**100%**	100%	100%	**100%**	100%

- Canadian Natural's North America E&P crude oil and NGL production volumes, excluding thermal in situ averaged 219,763 bbl/d in Q2/21, increases of 9% and 4% from Q2/20 and Q1/21 levels respectively. The increases from prior periods were primarily due to strong drilling results and execution on high value volume adding development activities (recompletions, workovers and reactivations) that capture improved commodity pricing, partially offset by natural field declines.
  - Primary heavy crude oil production averaged 65,992 bbl/d in Q2/21, increases of 6% and 5% from Q2/20 and Q1/21 levels respectively, primarily due to strong drilling results and development activities, partially offset by natural field declines.
    - Operating costs in the Company's primary heavy crude oil operations averaged $19.32/bbl (US$15.73/bbl) in Q2/21, an increase of 8% from Q2/20 levels, primarily as a result of increased power costs.
    - At the Company's Clearwater play at Smith, 6 net horizontal multilateral wells are now all on-stream. Production from these 6 wells continues to be strong, currently totaling approximately 2,200 bbl/d, exceeding budgeted rates by 600 bbl/d from these wells.
    - The Company is currently drilling a second 6 net horizontal multilateral well pad at Smith, targeted to be on stream in Q4/21. This pad is targeting similarly strong productive rates of approximately 2,000 bbl/d.
  - Pelican Lake production was strong in Q2/21 averaging 55,212 bbl/d, comparable with prior periods, demonstrating the strength of this long life low decline asset and the continued success of the Company's world class polymer flood.
    - The Company continues to focus on safe, effective and efficient operations, realizing low operating costs in Q2/21 at Pelican Lake, averaging $6.90/bbl (US$5.62/bbl), an increase of 9% from Q2/20 primarily due to increased power costs. Operating costs decreased 7% from Q1/21 levels primarily due to the impact of seasonality.
    - The Company drilled and brought on stream 10 net wells throughout Q2/21 at Pelican Lake. Current production from these wells is strong totaling approximately 1,300 bbl/d, at an attractive capital efficiency of approximately $9,900 per flowing BOE for this long life low decline asset.
  - North America light crude oil and NGL production averaged 98,559 bbl/d in Q1/21, increases of 20% and 6% from Q2/20 and Q1/21 levels respectively. The increases are primarily due to strong drilling results and development activities.
    - Operating costs in the Company's North America light crude oil and NGL areas averaged $14.39/bbl (US$11.72/bbl) in Q2/21, comparable with Q2/20 levels, and a decrease of 10% from Q1/21 levels primarily as a result of higher production volumes and effective and efficient operations, offset by increased power costs.
    - The Company continues to advance its high value Montney light crude oil development plan at Wembley, where 13 net wells have been drilled to date, ahead of schedule and under cost, of the budgeted 18 net wells targeted to be on stream in 2021.
      - Cost efficiencies have been realized on the Wembley drilling program as targeted costs are 12% lower than budgeted levels, resulting in a strong capital efficiency of approximately $8,300 per flowing BOE once on stream.
      - Construction of the new crude oil battery and gathering system is approximately 45 days ahead of schedule, now targeted to be on stream in mid-August 2021, with costs targeted to be 11% under budget.
      - This project is targeting to exit 2021 at total production rates of approximately 8,500 bbl/d of liquids and 30 MMcf/d of natural gas.

Thermal In Situ Oil Sands

	Three Months Ended			Six Months Ended	
	June 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Bitumen production (bbl/d)	**258,551**	267,530	212,807	**263,016**	220,555
Net wells targeting bitumen	**4**	3	—	**7**	6
Net successful wells drilled	**4**	3	—	**7**	6
Success rate	**100%**	100%	—%	**100%**	100%

- Canadian Natural's thermal in situ production averaged 258,551 bbl/d in Q2/21, an increase of 21% over Q2/20 levels and a decrease of 3% from Q1/21 levels.
  - Strong operating costs from the Company's thermal in situ assets were achieved in Q2/21, averaging $11.78/bbl (US$9.59/bbl), increases of 16% and 3% from Q2/20 and Q1/21 levels respectively. The increase in operating costs from Q2/20 was primarily due to increased energy costs and the increase from Q1/21 was primarily as a result of lower volumes in Q2/21 from Q1/21 levels.
- Solvent enhanced oil recovery technology is being piloted by the Company with an objective to increase bitumen production, reduce the Steam to Oil Ratio ("SOR"), reduce greenhouse gas ("GHG") intensity and have high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At Kirby South, results from our on-going two year pilot of this technology indicate a significant SOR and GHG intensity reduction of approximately 45%, within the targeted range, can be achieved with the process. Monitoring of solvent recovery will continue for the remainder of 2021 to conclude the pilot results.
  - At Primrose, in the steam flood area, a solvent injection pilot is targeted to commence in Q4/21. The Company's second pilot will consist of 9 net wells (5 producers and 4 injectors) and similar to the first pilot at Kirby South, is targeted to operate for a two year period.

North America Natural Gas

	Three Months Ended			Six Months Ended	
	June 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Natural gas production (MMcf/d)	**1,594**	1,585	1,431	**1,589**	1,419
Net wells targeting natural gas	**9**	22	1	**31**	12
Net successful wells drilled	**9**	22	1	**31**	12
Success rate	**100%**	100%	100%	**100%**	100%

- North America natural gas production was strong in Q2/21 averaging 1,594 MMcf/d, an increase of 11% from Q2/20 levels and comparable with Q1/21 levels. The increase from Q2/20 was primarily as a result of acquired production in Q4/20 and strong drilling results, partially offset by natural field declines and the temporary full quarter shutdown of the Pine River Gas Plant, which resumed operations on July 24, 2021, restoring production of approximately 100 MMcf/d.
  - North America natural gas operating costs in Q2/21 averaged $1.15/Mcf, an increase of 4% from Q2/20 levels and a decrease of 7% from Q1/21 levels. The increase from Q2/20 was primarily due to the increase in electricity costs. The decrease from Q1/21 was primarily due to the impact of seasonality.
- As part of the 2021 budget, in the liquids rich Montney, the Company targets to utilize facility capacity through its drill to fill strategy adding low cost, high value liquids rich natural gas volumes.
  - At Septimus, a 5 net well pad came on stream in June 2021 as budgeted, with total rates currently limited to approximately 30 MMcf/d of natural gas and 230 bbl/d of liquids, resulting in a strong capital efficiency of approximately $5,000 per flowing BOE.

- ◦ As a result, production at Septimus reached full facility capacity of 150 MMcf/d of natural gas and 9,000 bbl/d of liquids in June 2021 and targets to remain at full capacity for the remainder of 2021.
- ◦ Operating costs at Septimus remained strong in Q2/21, averaging $0.32/Mcfe, comparable with Q2/20 levels of $0.31/Mcfe.

- At Townsend, a 6 net well pad came on stream in June 2021, with total rates of approximately 55 MMcf/d of natural gas, exceeding targeted rates by approximately 11 MMcf/d, resulting in a strong capital efficiency of approximately $4,000 per flowing BOE.
  - ◦ As a result, production at Townsend of approximately 265 MMcf/d of natural gas was achieved in Q2/21 and remains on target to exit 2021 at a production rate of approximately 340 MMcf/d.

International Exploration and Production

	Three Months Ended			Six Months Ended	
	June 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Crude oil production (bbl/d)					
North Sea	**16,458**	19,959	26,627	**18,199**	27,191
Offshore Africa	**16,239**	11,854	17,444	**14,059**	16,694
Natural gas production (MMcf/d)					
North Sea	**4**	4	15	**4**	19
Offshore Africa	**16**	9	16	**13**	13
Net wells targeting crude oil	**1.0**	2.0	—	**3.0**	1.0
Net successful wells drilled	**1.0**	2.0	—	**3.0**	1.0
Success rate	**100%**	100%	—%	**100%**	100%

- ▪ International E&P crude oil production volumes averaged 32,697 bbl/d in Q2/21, a decrease of 26% from Q2/20 levels and a 3% increase from Q1/21 levels. The fluctuations in production from prior periods was primarily as a result of planned maintenance activities, natural field declines and the permanent cessation of production from the Banff and Kyle fields in 2020.
  - Crude oil operating costs increased from prior periods primarily due to lower volumes due to planned maintenance activities in the North Sea and Offshore Africa on a relatively fixed cost base and increased energy and GHG costs in the North Sea.
  - In Q3/21 the Company is planning turnarounds at the Ninian Central platform in the North Sea and at Espoir in Offshore Africa. Targeted production impacts were included in the Company's annual 2021 budgeted production volume range.

North America Oil Sands Mining and Upgrading

	Three Months Ended			Six Months Ended	
	June 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Synthetic crude oil production (bbl/d) (1) (2)	**361,707**	468,803	464,318	**414,959**	451,210

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

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

- The Company's world class Oil Sands Mining and Upgrading assets averaged quarterly production of 361,707 bbl/d of SCO in Q2/21, decreases of 22% and 23% from Q2/20 and Q1/21 levels respectively, due to the timing of the planned turnaround at Horizon and de-coking at Scotford, which were both completed in the second quarter of 2021.
    - Operating costs from the Company's Oil Sands Mining and Upgrading assets remain top tier averaging $25.46/bbl (US$20.73/bbl) of SCO in Q2/21, strong results given significantly less quarterly sales volumes of approximately 100,000 bbl/d compared to Q1/21 levels as a result of the planned turnaround at Horizon, de-coking at Scotford and maintenance activities at the Albian mines.
    - The Company's focus on continuous improvement initiatives delivered high utilization and reliability at the Company's Oil Sands Mining and Upgrading assets. As a result, record monthly SCO production of approximately 495,100 bbl/d was achieved in June 2021, an increase from the previous record of approximately 490,800 bbl/d of SCO achieved in December 2020.

MARKETING

	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	June 30 2020	**June 30 2021**	June 30 2020
Crude oil and NGLs pricing					
WTI benchmark price (US$/bbl) (1)	**$ 66.06**	$ 57.80	$ 27.85	**$ 61.95**	$ 36.97
WCS heavy differential as a percentage of WTI (%) (2)	**17%**	21%	41%	**19%**	43%
SCO price (US$/bbl)	**$ 66.49**	$ 54.30	$ 23.28	**$ 60.43**	$ 33.33
Condensate benchmark pricing (US$/bbl)	**$ 66.39**	$ 57.99	$ 22.19	**$ 62.22**	$ 33.86
Average realized pricing before risk management (C$/bbl) (3)	**$ 61.20**	$ 52.68	$ 18.97	**$ 56.87**	$ 22.70
Natural gas pricing					
AECO benchmark price (C$/GJ)	**$ 2.70**	$ 2.77	$ 1.81	**$ 2.74**	$ 1.92
Average realized pricing before risk management (C$/Mcf)	**$ 3.17**	$ 3.42	$ 2.03	**$ 3.29**	$ 2.13

(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.

- Crude oil prices continue to improve with WTI averaging US$66.06/bbl in Q2/21, an increase of 137% from Q2/20 levels. The increase in WTI from comparable periods primarily reflected increased demand as a result of the positive impact of the global roll out of COVID-19 vaccinations on economic activity, the continuation of agreements by OPEC+ to maintain the majority of production cuts implemented in 2020 and the strengthening of the global economy.
    - As at July 26, 2021 for crude oil, annual WTI pricing of US$66.31/bbl is currently 68% higher than 2020 levels and the annual WCS heavy oil differential has improved significantly from 2020, currently at approximately 20% discount to WTI, in line with average historical levels.
- Natural gas prices continue to improve with AECO averaging $2.70/GJ in Q2/21, an increase of 49% from Q2/20 levels. The increase in natural gas prices from the comparable period primarily reflected lower storage levels and increased NYMEX benchmark pricing.
- Market egress is targeted to improve in the short- and mid-term as construction is progressing on the Trans Mountain Expansion ("TMX") and the Enbridge Line 3 replacement.
    - Enbridge Line 3 is targeted to be on stream in Q4/21.
    - 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 on-stream in the latter half of 2021.

- TMX construction is on track for a targeted on stream date in early 2023, on which Canadian Natural has 94,000 bbl/d committed capacity.
- The North West Redwater ("NWR") Refinery has targeted processing capacity of approximately 80,000 bbl/d of diluted bitumen, which improves heavy oil demand in western Canada, effectively increasing egress out of the WCSB. 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, averaged quarterly production of 1,141,739 BOE/d in Q2/21, with approximately 98% of total production located in G7 countries.
- In Q2/21, reflecting the strength of our effective and efficient operations and our high quality, long life low decline asset base, Canadian Natural generated robust quarterly free cash flow of $1,535 million, after dividend payments of $557 million and net capital expenditures of $957 million, excluding acquisitions.
  - Canadian Natural executed on our commitment to further strengthen our balance sheet with strong financial results in Q2/21, reducing net debt by approximately $1.7 billion from Q1/21 levels. Net debt has decreased by approximately $3.1 billion in the first two quarters of 2021.
    - In Q2/21 the Company fully repaid and retired the remaining outstanding balance on its $2,125 million non-revolving term loan. The facility originally matured in June 2022.
    - Subsequent to quarter end the Company exercised a 90-day par call option on its US$500 million 3.45% notes originally due November 15, 2021 with repayment to occur on August 16, 2021.
    - As at June 30, 2021, the Company had undrawn revolving bank credit facilities of approximately $5.0 billion. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $5.6 billion. At June 30, 2021, the Company had approximately $0.7 billion drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
- Returns to shareholders year to date in 2021 have been significant, as Canadian Natural has returned approximately $1.5 billion by way of dividends and share repurchases up to and including August 4, 2021.
  - In March 2021, the Company declared a quarterly dividend of $0.47 per share, an increase of 11% from the previous level of $0.425 per share, marking 2021 as the Company's 21st consecutive year of dividend increases, reflecting the Board of Directors' confidence in Canadian Natural's strength and the robustness of the Company's assets and its ability to generate significant and sustainable free cash flow.
    - Subsequent to quarter end the Company declared a quarterly dividend of $0.47 per share, payable on October 5, 2021.
  - In March 2021, the Board of Directors authorized management to repurchase shares under a NCIB to approximately offset options exercised throughout the coming year, in order to minimize or eliminate dilution to shareholders.
    - Share repurchases for cancellation in 2021 up to and including August 4, 2021 total 11,044,400 common shares at a weighted average price of $42.00.
- Annual 2021 free cash flow is targeted to be robust at a range of $7.2 billion to $7.7 billion using an annual average WTI of US$66/bbl, after dividends and budgeted capital expenditures, excluding net acquisitions.
  - Free cash flow generation has been significant in 2021 and the Company's balance sheet continues to strengthen, providing the Board of Directors the confidence to approve a more defined free cash flow allocation policy in accordance with the Company's four pillars of capital allocation. Effective July 1, 2021 under the new policy, the Company targets to allocate free cash flow as follows:
    - Increased returns to shareholders through incremental share repurchases of approximately 1% of common shares outstanding or approximately 11 million shares per quarter.

    - Once the Company reaches $15.0 billion in absolute debt, currently targeted to occur in Q4/21, 50% of free cash flow is targeted to be allocated to share repurchases under the Company's NCIB, with the remaining 50% allocated to further strengthening of the Company's balance sheet.
- Subsequent to quarter end, in July 2021, the Company filed base shelf prospectuses that allow for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada and US$3,000 million of debt securities in the United States, which expire August 2023, replacing the Company's previous base shelf prospectuses which would have expired 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.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE ("ESG") HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver responsibly produced energy that the world needs through leading ESG performance. Canadian Natural's culture of continuous improvement provides a significant advantage and results in continued improvement in the Company's environmental performance.

On June 9, 2021 Canadian Natural together with oil sands industry participants formally announced the Oil Sands Pathways to Net Zero initiative. Canadian Natural and these companies operate approximately 90% of Canada’s oil sands production. The goal of this unique alliance, working collectively with the federal and Alberta governments, is to achieve net zero GHG emissions from oil sands operations by 2050 to help Canada meet its climate goals, including its Paris Agreement commitments and 2050 net zero aspirations.

- This collaborative effort follows welcome announcements from the Government of Canada and the Government of Alberta of important support programs for emissions-reduction projects and infrastructure. Collaboration between industry and government will be critical to progressing the Oil Sands Pathways to Net Zero vision and achieving Canada’s climate goals.
- The Pathways vision is anchored by a major Carbon Capture, Utilization and Storage ("CCUS") trunkline connected to a carbon sequestration hub to enable multi-sector ‘tie-in’ projects for expanded emissions reductions. The proposed CCUS system is similar to the multi-billion dollar Longship/Northern Lights project in Norway as well as other CCUS projects in the Netherlands, UK and USA, all of which involve significant collaboration between industry and government.
- The Pathways initiative is ambitious and will require significant investment on the part of both industry and government to advance the research and development of new and emerging technologies.
- The companies involved look forward to continuing to work with governments and to engage with Indigenous and local communities in northern Alberta, to make this ambitious, major emissions-reduction vision a reality so those communities can continue to benefit from Canadian resource development.

Canadian Natural plans to publish its 2020 Stewardship Report to Stakeholders in August, which will be available on the Company's website at https://www.cnrl.com/report-to-stakeholders. The report displays how Canadian Natural continues to focus on safe, reliable, effective and efficient operations while minimizing its environmental footprint. Canadian Natural outlined its pathway to lower carbon emissions and its journey to achieve its goal of net zero GHG emissions in the oil sands. Highlights from the Company's 2020 report are as follows:

- Canadian Natural's corporate GHG emissions intensity continues to improve, decreasing by 18% from 2016 to 2020, a material reduction in emissions intensity.
- The Company reduced methane emissions in its North American E&P segment by 28% from 2016 to 2020.
- The Company continues to improve corporate total recordable injury frequency ("TRIF") in 2020, with a TRIF of 0.21 in 2020 compared to 0.50 in 2016. The Company's TRIF is down 58% since 2016, while man-hours have increased over this time period.
- Canadian Natural is one of the largest owners of Carbon Capture and Storage ("CCS") and sequestration capacity in the oil and natural gas sector globally through projects at Horizon, the Company’s 70% owned Quest CCS facility located at Scotford, and its 50% working interest in the NWR Refinery. As part of our comprehensive GHG emissions reduction strategy, our CCS projects include carbon dioxide ("CO_2") storage in geological formations, the use of CO_2 in enhanced oil recovery techniques and injection of CO_2 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 cars off the road per year.

- The Quest CCS (70% Company ownership) facility captures and stores approximately 1.1 million tonnes of CO_2 per year, the equivalent of removing approximately 235,000 cars off the road annually. In May 2020 Quest reached the milestone of 5 million tonnes of stored carbon dioxide, equal to the emissions from approximately 1.25 million cars.
- At Horizon, annual capture capacity is approximately 0.4 million tonnes of CO_2 from the hydrogen plant, the equivalent of removing approximately 85,000 cars off the road annually.
- At the NWR Refinery, captured CO_2 from the refinery began delivery in March 2020 to the Alberta Carbon Truck Line for enhanced oil recovery and permanent storage in central Alberta. At full capacity, approximately 1.2 million tonnes of CO_2 per year will be captured, the equivalent of removing approximately 256,000 cars off the road annually.

▪ The Company continues to increase the level of third party verified direct GHG emissions and indirect energy use.
  - The Company targets to increase the total corporate level of third party verification of GHG emissions to 95% in 2021, an increase of 9% from 2020 levels of 87%.

▪ In 2020 the Company planted its one millionth tree at AOSP and its one and a half millionth tree at Horizon, reclaiming land and contributing to increased carbon capture.

The Government of Canada's announcement on April 19, 2021 of its 2021 budget recognized the important role of carbon capture, utilization and storage projects for the oil sands sector to continue contributing to Canada’s economic growth while working towards climate objectives. As a leader in Carbon, CCUS, Canadian Natural sees many opportunities for industry to advance investments in CCUS projects. Details of the proposed government program are important and the Company looks forward to working together with government through the consultation period.

ENVIRONMENTAL TARGETS

▪ The Company has successfully achieved our four previously issued environmental targets relating to GHG emissions intensity reductions, methane emissions reductions and reduced fresh water usage as follows:
  - 25% reduction in oil sands GHG emissions intensity by 2025, from a 2016 baseline.
    - As of 2020, Canadian Natural reduced oil sands GHG emissions intensity by 38%.
  - 20% reduction in North America E&P, including thermal in situ, methane emissions by 2025, from a 2016 baseline.
    - As of 2020, Canadian Natural reduced North America E&P, including thermal in situ, methane emissions by 28%.
  - 50% reduction of in situ fresh water usage intensity by 2022, from a 2012 baseline.
    - As of 2020, Canadian Natural reduced the in situ fresh water usage intensity by 75%.
  - 30% reduction in mining fresh river water usage intensity by 2022, from a 2012 baseline.
    - As of 2020, Canadian Natural reduced the mining river fresh water usage intensity by 70%.

▪ Based on achieving the Company's interim environmental targets referred to above, Canadian Natural has committed to new environmental targets as follows:
  - 50% reduction in North America E&P, including thermal in situ, methane emissions by 2030, from a 2016 baseline.
  - 40% reduction in thermal in situ fresh water usage intensity by 2026, from a 2017 baseline.
  - 40% reduction in mining fresh river water usage intensity by 2026, from a 2017 baseline.

- In 2018, Canadian Natural was one of the first oil companies to announce an aspirational goal of achieving net zero emissions in its oil sands operations.
- Through the Company’s participation in the Oil Sands Pathways to Net Zero Initiative with our industry partners and collaboration with the federal and Alberta governments, the Company is further refining its goal by targeting to achieve net zero emissions in its oil sands operations by 2050.
- The Company is currently working through the details with members of the net zero initiative alliance to advance key milestones to be achieved over the next decade as we accelerate related projects through the Pathways initiative.

CORPORATE UPDATE

Canadian Natural is pleased to announce the appointment of Ms. Dawn L. Farrell to the Board of Directors of the Company, effective August 4, 2021. Ms. Farrell was most recently the President and Chief Executive Officer of TransAlta Corporation since 2012, before retiring in March of this year, having previously held roles as Chief Operating Officer from 2009 to 2011 and Executive Vice-President, Commercial Operations and Development from 2008 to 2009. Ms. Farrell has over 30 years of experience in the electric energy industry, holding executive leadership positions at both TransAlta and at BC Hydro and currently sits on the Board of Directors of The Chemours Company, a NYSE listed chemicals company, and is Chancellor of Mount Royal University. Ms. Farrell holds a Bachelor of Commerce and a Master of Arts in Economics, both from the University of Calgary, and has attended the Advanced Management Program at Harvard University.

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 from (used in) operating activities, and cash flows used in investing activities as determined in accordance with IFRS, as an indication of the Company's performance.

Adjusted net earnings (loss) from operations is a non-GAAP financial measure that represents net earnings (loss), as determined in accordance with IFRS, 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. Adjusted net earnings (loss) from operations may not be comparable to similar measures presented by other companies.

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from (used in) operating activities, as determined in accordance with IFRS, as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), 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. Adjusted funds flow may not be comparable to similar measures presented by other companies.

Net capital expenditures is a non-GAAP financial measure, as determined in accordance with IFRS, 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, the repayment of NWRP subordinated debt advances, abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs, and the settlement of long-term debt assumed in acquisitions. The Company considers net capital expenditures a key measure in evaluating its performance, as it provides an understanding of the Company’s capital spending activities in comparison to the Company's annual capital budget. Net capital expenditures may not be comparable to similar measures presented by other companies.

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.

Long-term debt, net and net debt are other financial measures that are calculated as net current and long-term debt less cash and cash equivalents.

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 and short term investments, less amounts drawn on the bank and credit facilities including under the commercial paper program. The Company considers available liquidity a key measure in evaluating the sustainability of the Company’s operations and ability to fund future growth. See note 8 - Long-term Debt in the Company’s consolidated financial statements.

Special Note Regarding Currency, Financial Information and Production

The Company's 2021 targeted annual adjusted funds flow, free cash flow and net debt are based upon forecasted commodity prices of US$66.31 WTI/bbl, WCS discount of US$12.94/bbl, AECO price of C$3.29/GJ and FX of US$1.00 to C$1.25. Forecasted net debt reflects estimated timing of cash receipts and expenditures.

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, the disposition of shares of Inter Pipeline Ltd. ("IPL") to a third-party provided that all conditions of the third-party offer are satisfied, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses and other targets 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 oil projects, the Pelican Lake water and polymer flood projects, 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, the development and deployment of technology and technological innovations, and the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long term 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 earlier 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 Plus ("OPEC+") 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+ taken in response to COVID-19 or otherwise; fluctuations in currency and interest rates; assumptions on which the Company's current targets are 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; the Company's ability to meet its targeted production levels; 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 sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short, medium, and long term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; 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 from (used in) 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 from (used in) 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, 2021 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2020. 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, 2021 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, 2021 in relation to the comparable periods in 2020 and the first quarter of 2021. 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, 2020, 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 4, 2021.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Jun 30 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
Product sales [1]	**$ 7,124**	$ 7,019	$ 2,944	**$ 14,143**	$ 7,596
Crude oil and NGLs	**$ 6,382**	$ 6,288	$ 2,462	**$ 12,670**	$ 6,785
Natural gas	**$ 509**	$ 555	$ 307	**$ 1,064**	$ 644
Net earnings (loss)	**$ 1,551**	$ 1,377	$ (310)	**$ 2,928**	$ (1,592)
Per common share – basic	**$ 1.31**	$ 1.16	$ (0.26)	**$ 2.47**	$ (1.35)
– diluted	**$ 1.30**	$ 1.16	$ (0.26)	**$ 2.46**	$ (1.35)
Adjusted net earnings (loss) from operations [2]	**$ 1,480**	$ 1,219	$ (772)	**$ 2,699**	$ (1,067)
Per common share – basic	**$ 1.25**	$ 1.03	$ (0.65)	**$ 2.28**	$ (0.90)
– diluted	**$ 1.24**	$ 1.03	$ (0.65)	**$ 2.27**	$ (0.90)
Cash flows from (used in) operating activities	**$ 2,940**	$ 2,536	$ (351)	**$ 5,476**	$ 1,374
Adjusted funds flow [3]	**$ 3,049**	$ 2,712	$ 415	**$ 5,761**	$ 1,752
Per common share – basic	**$ 2.57**	$ 2.29	$ 0.35	**$ 4.86**	$ 1.48
– diluted	**$ 2.56**	$ 2.28	$ 0.35	**$ 4.85**	$ 1.48
Cash flows used in investing activities	**$ 719**	$ 648	$ 693	**$ 1,367**	$ 1,552
Net capital expenditures [4]	**$ 1,285**	$ 808	$ 421	**$ 2,093**	$ 1,259

(1) Further details related to product sales are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

(2) Adjusted net earnings (loss) from operations is a non-GAAP 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 from (used in) 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 excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to North West Redwater Partnership ("NWRP"), and prepaid cost of service tolls. The Company considers adjusted funds flow a key measure in evaluating its performance, as it demonstrates the Company's ability to generate the cash flow necessary to fund future growth through capital investment and to repay debt. The reconciliation "Adjusted Funds Flow, as Reconciled to Cash Flows from (used in) 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, the repayment of NWRP subordinated debt advances, and abandonment expenditures including the impact of government grant income under the provincial well-site rehabilitation programs. The Company considers net capital expenditures a key measure in evaluating its performance, 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 2021**	 Mar 31 2021	 Jun 30 2020	Six Months Ended **Jun 30 2021**	 Jun 30 2020
Net earnings (loss)	**$ 1,551**	$ 1,377	$ (310)	**$ 2,928**	$ (1,592)
Share-based compensation, net of tax (1)	**132**	126	23	**258**	(198)
Unrealized risk management loss (gain), net of tax (2)	**6**	15	1	**21**	(14)
Unrealized foreign exchange (gain) loss, net of tax (3)	**(151)**	(172)	(433)	**(323)**	688
Realized foreign exchange gain on settlement of cross currency swaps, net of tax (4)	**—**	—	—	**—**	(166)
(Gain) loss from investments, net of tax (5)	**(47)**	(117)	(53)	**(164)**	215
Other, net of tax (6)	**(11)**	(10)	—	**(21)**	—
Adjusted net earnings (loss) from operations	**$ 1,480**	$ 1,219	$ (772)	**$ 2,699**	$ (1,067)

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and Performance Share Unit ("PSU") plan. The fair value of the share-based compensation is recognized 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 recognized 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 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 investments in PrairieSky Royalty Ltd. ("PrairieSky") and IPL 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).

(6) "Other" reflects the after-tax impact of government grant income under the provincial well-site rehabilitation programs.

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

($ millions)	Three Months Ended **Jun 30 2021**	 Mar 31 2021	 Jun 30 2020	Six Months Ended **Jun 30 2021**	 Jun 30 2020
Cash flows from (used in) operating activities	**$ 2,940**	$ 2,536	$ (351)	**$ 5,476**	$ 1,374
Net change in non-cash working capital	**137**	10	739	**147**	144
Abandonment expenditures (1)	**44**	67	40	**111**	129
Other (2)	**(72)**	99	(13)	**27**	105
Adjusted funds flow	**$ 3,049**	$ 2,712	$ 415	**$ 5,761**	$ 1,752

(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 and excludes the impact of government grant income under the provincial well-site rehabilitation programs.

(2) Movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP and prepaid cost of service tolls.

SUMMARY OF FINANCIAL HIGHLIGHTS

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

Net earnings for the six months ended June 30, 2021 were $2,928 million compared with a net loss of $1,592 million for the six months ended June 30, 2020. Net earnings for the six months ended June 30, 2021 included net after-tax income of $229 million compared with net after-tax expenses of $525 million for the six months ended June 30, 2020 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the foreign exchange gain on the settlement of the cross currency swaps, the (gain) loss from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the six months ended June 30, 2021 were $2,699 million compared with an adjusted net loss from operations of $1,067 million for the six months ended June 30, 2020.

Net earnings for the second quarter of 2021 were $1,551 million compared with a net loss of $310 million for the second quarter of 2020 and net earnings of $1,377 million for the first quarter of 2021. Net earnings for the second quarter of 2021 included net after-tax income of $71 million compared with net after-tax income of $462 million for the second quarter of 2020 and net after-tax income of $158 million for the first quarter of 2021 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain from investments, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the second quarter of 2021 were $1,480 million compared with an adjusted net loss from operations of $772 million for the second quarter of 2020 and adjusted net earnings from operations of $1,219 million for the first quarter of 2021.

Net earnings and adjusted net earnings from operations for the three and six months ended June 30, 2021 compared with a net loss and adjusted net loss from operations for the three and six months ended June 30, 2020 primarily reflected:

- higher crude oil and NGLs and natural gas netbacks in the Exploration and Production segments;
- higher crude oil and NGLs and natural gas sales volumes in the North America segment; and
- higher realized prices in the Oil Sands Mining and Upgrading segment, partially offset by lower sales volumes.

Net earnings and adjusted net earnings from operations for the second quarter of 2021 compared with net earnings and adjusted net earnings from operations for the first quarter of 2021 primarily reflected:

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

partially offset by:

- lower sales volumes in the Oil Sands Mining and Upgrading segment; and
- lower natural gas netbacks in the North America segment.

The impacts of share-based compensation, risk management activities, fluctuations in foreign exchange rates, income from NWRP, and (gain) loss from investments, 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 from (used in) Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the six months ended June 30, 2021 were $5,476 million compared with $1,374 million for the six months ended June 30, 2020. Cash flows from operating activities for the second quarter of 2021 were $2,940 million compared with cash flows used in operating activities of $351 million for the second quarter of 2020 and cash flows from operating activities of $2,536 million for the first quarter of 2021. The fluctuations in cash flows from (used in) operating activities from the comparable periods were primarily due to the factors previously noted relating to the fluctuations in net earnings (loss) from operations, as well as due to the impact of changes in non-cash working capital.

Adjusted funds flow for the six months ended June 30, 2021 was $5,761 million compared with $1,752 million for the six months ended June 30, 2020. Adjusted funds flow for the second quarter of 2021 was $3,049 million compared with $415 million for the second quarter of 2020 and $2,712 million for the first quarter of 2021. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above relating to the fluctuations in cash flows from (used in) operating activities excluding the impact of the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets, including the unamortized cost of the share bonus program, accrued interest on subordinated debt advances to NWRP, and prepaid cost of service tolls.

Production Volumes

Total production of crude oil and NGLs before royalties for the second quarter of 2021 decreased 5% to 872,718 bbl/d, from 921,895 bbl/d for the second quarter of 2020 and decreased 11% from 979,352 bbl/d for the first quarter of 2021. Total natural gas production before royalties for the second quarter of 2021 increased 10% to 1,614 MMcf/d from 1,462 MMcf/d for the second quarter of 2020 and was comparable with 1,598 MMcf/d for the first quarter of 2021. Total production before royalties for the second quarter of 2021 of 1,141,739 BOE/d was comparable with 1,165,487 BOE/d for the second quarter of 2020 and decreased 8% from 1,245,703 BOE/d for the first quarter of 2021. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production" section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, crude oil and NGLs realized prices averaged $61.20 per bbl in the second quarter of 2021, an increase of 223% compared with $18.97 per bbl for the second quarter of 2020, and an increase of 16% from $52.68 per bbl for the first quarter of 2021. The natural gas realized price increased 56% to average $3.17 per Mcf for the second quarter of 2021 from $2.03 per Mcf for the second quarter of 2020, and decreased 7% from $3.42 per Mcf for the first quarter of 2021. In the Oil Sands Mining and Upgrading segment, the Company's SCO realized price increased 162% to average $76.19 per bbl for the second quarter of 2021 from $29.11 per bbl for the second quarter of 2020, and increased 18% from $64.60 per bbl for the first quarter of 2021. The Company's realized pricing reflects prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the "Business Environment", "Product Prices – Exploration and Production", and the "Oil Sands Mining and Upgrading" sections of this MD&A.

Production Expense

In the Company's Exploration and Production segments, crude oil and NGLs production expense averaged $13.75 per bbl for the second quarter of 2021, an increase of 10% from $12.53 per bbl for the second quarter of 2020, and a decrease of 6% from $14.56 per bbl for the first quarter of 2021. Natural gas production expense averaged $1.19 per Mcf for the second quarter of 2021, an increase of 3% from $1.15 per Mcf for the second quarter of 2020 and a decrease of 6% from $1.27 per Mcf for the first quarter of 2021. In the Oil Sands Mining and Upgrading segment, production costs averaged $25.46 per bbl for the second quarter of 2021, an increase of 44% from $17.74 per bbl for the second quarter of 2020, and an increase of 28% from $19.82 per bbl for the first quarter of 2021. Crude oil and NGLs and natural gas production expense is discussed in detail in the "Production Expense – Exploration and Production" and the "Oil Sands Mining and Upgrading" sections 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 2021**		Mar 31 2021		Dec 31 2020		Sep 30 2020
Product sales [(1)]	**$**	**7,124**	$	7,019	$	5,219	$	4,676
Crude oil and NGLs	**$**	**6,382**	$	6,288	$	4,592	$	4,202
Natural gas	**$**	**509**	$	555	$	496	$	338
Net earnings (loss)	**$**	**1,551**	$	1,377	$	749	$	408
Net earnings (loss) per common share								
– basic	**$**	**1.31**	$	1.16	$	0.63	$	0.35
– diluted	**$**	**1.30**	$	1.16	$	0.63	$	0.35

($ 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

(1) Further details related to product sales for the three months ended June 30, 2021 and 2020 are disclosed in note 17 to the Company's unaudited interim consolidated financial statements.

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

- **Crude oil pricing** – Fluctuating global supply/demand including crude oil production levels from 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; 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 on January 1, 2019 and were suspended effective December 1, 2020.
- **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 oil projects, production from the Kirby Thermal Oil Sands Project, 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 of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, production curtailments mandated by the Government of Alberta that came into effect January 1, 2019 and were suspended effective December 1, 2020, 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 high return projects, drilling results, natural decline rates, the temporary shut-down of the Pine River gas plant, and the impact and timing of acquisitions, including the acquisition in the fourth quarter of 2020.
- **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 seasonality, 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, and maintenance activities in the International segments.
- **Transportation, blending, and feedstock expense** – Fluctuations due to the provision recognized relating to the Keystone XL pipeline project in the fourth quarter of 2020.
- **Depletion, depreciation and amortization expense** – 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, and the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment.
- **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 changing long-term debt levels, and the impact of movements in benchmark interest rates on outstanding floating rate long-term debt.
- **Foreign exchange** – 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.
- **Gain on acquisition, gains/losses on investments and income from NWRP** – Fluctuations due to the recognition of a gain on the acquisition in the fourth quarter of 2020, fair value changes in the investments in PrairieSky and IPL shares, equity income and losses on the Company's interest in NWRP, and the distribution from NWRP in the second quarter of 2021.
- **Income taxes** – Fluctuations due to statutory tax rate and other legislative changes substantively enacted in the various periods.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices increased significantly in the first half of 2021, partially in response to the OPEC+ decision to maintain substantially all of the production cut agreements implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions, as the effects of COVID-19 become less impactful to the global economy. Economic conditions and the outlook for crude oil prices remain somewhat uncertain.

During the second quarter of 2021, the Company continued to utilize federal and provincial government programs to support employment during the COVID-19 pandemic, including in Canada, the provincial well-site rehabilitation program.

Liquidity

As at June 30, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,596 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At June 30, 2021, the Company had $682 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Refer to the "Liquidity and Capital Resources" section of this MD&A for further details.

Capital Spending

Safe, reliable, effective and efficient operations continue to be a focus for the Company. On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets. Production for 2021 is now targeted between 1,220,000 BOE/d and 1,267,000 BOE/d. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons.

Year to date in 2021 to the end of July, the Company has completed three opportunistic acquisitions. The first two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d, consisting of 63 MMcf/d and 600 bbl/d of NGLs, approximately 107,000 acres of Montney lands, and related processing infrastructure with approximately 140 MMcf/d of capacity. These two acquisitions build on the Company's expansive natural gas operations in northeastern British Columbia, increasing the Company's total Montney lands to approximately 1.3 million acres. The third acquisition consisted of a net carried interest on an existing Canadian Natural oil sands lease, from which all of the Company's current Horizon volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million, and the Company's 2021 capital budget will increase by this amount.

The Company owns approximately 6.4 million shares of IPL, which is currently subject to a third-party offer to purchase, of which the current value is approximately $130 million to the Company. Provided that all conditions of the third-party offer for IPL shares are satisfied, the Company targets to utilize these proceeds to further invest in value adding opportunities in the Company's vast asset base, and plans to increase its 2021 capital budget, excluding acquisitions, to approximately $3,480 million, including approximate additions of $120 million related to conventional and unconventional assets, $110 million related to long-life low decline assets, and an additional $45 million related to abandonment and reclamation activities. The 2021 capital budget and production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Risks and Uncertainties

COVID-19, including variants of concern, 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 2021	Three Months Ended Mar 31 2021	Three Months Ended Jun 30 2020	Six Months Ended Jun 30 2021	Six Months Ended Jun 30 2020
WTI benchmark price (US$/bbl)	**$ 66.06**	$ 57.80	$ 27.85	**$ 61.95**	$ 36.97
Dated Brent benchmark price (US$/bbl)	**$ 68.63**	$ 60.58	$ 31.38	**$ 64.63**	$ 40.90
WCS Heavy Differential from WTI (US$/bbl)	**$ 11.47**	$ 12.42	$ 11.53	**$ 11.95**	$ 16.00
SCO price (US$/bbl)	**$ 66.49**	$ 54.30	$ 23.28	**$ 60.43**	$ 33.33
Condensate benchmark price (US$/bbl)	**$ 66.39**	$ 57.99	$ 22.19	**$ 62.22**	$ 33.86
Condensate Differential from WTI (US$/bbl)	**$ (0.33)**	$ (0.19)	$ 5.66	**$ (0.27)**	$ 3.11
NYMEX benchmark price (US$/MMBtu)	**$ 2.83**	$ 2.69	$ 1.72	**$ 2.76**	$ 1.84
AECO benchmark price (C$/GJ)	**$ 2.70**	$ 2.77	$ 1.81	**$ 2.74**	$ 1.92
US/Canadian dollar average exchange rate (US$)	**$ 0.8143**	$ 0.7900	$ 0.7218	**$ 0.8020**	$ 0.7324

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.

Crude oil sales contracts in the North America segment are typically based on WTI benchmark pricing. WTI averaged US$61.95 per bbl for the six months ended June 30, 2021, an increase of 68% from US$36.97 per bbl for the six months ended June 30, 2020. WTI averaged US$66.06 per bbl for the second quarter of 2021, an increase of 137% from US$27.85 per bbl for the second quarter of 2020, and an increase of 14% from US$57.80 per bbl for the first quarter of 2021.

Crude oil sales contracts for the Company’s North Sea and Offshore Africa segments are typically based on Brent pricing, which is representative of international markets and overall world supply and demand. Brent averaged US$64.63 per bbl for the six months ended June 30, 2021, an increase of 58% from US$40.90 per bbl for the six months ended June 30, 2020. Brent averaged US$68.63 per bbl for the second quarter of 2021, an increase of 119% from US$31.38 per bbl for the second quarter of 2020, and an increase of 13% from US$60.58 per bbl for the first quarter of 2021.

The increase in WTI and Brent pricing for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected the OPEC+ decision to maintain substantially all of the production cut agreements that were implemented in the first half of 2020. Additionally, global demand for crude oil increased due to improved economic conditions. The increase in WTI and Brent pricing for the second quarter of 2021 from the first quarter of 2021 primarily reflected continued recovery in global demand.

The WCS Heavy Differential averaged US$11.95 per bbl for the six months ended June 30, 2021, a narrowing of 25% from US$16.00 per bbl for the six months ended June 30, 2020. The WCS Heavy Differential averaged US$11.47 per bbl for the second quarter of 2021, comparable with US$11.53 per bbl for the second quarter of 2020, and a narrowing of 8% from US$12.42 per bbl for the first quarter of 2021. The narrowing of the WCS Heavy Differential for the three and six months ended June 30, 2021 from the comparable periods primarily reflected continued recovery in North American refining demand.

The SCO price averaged US$60.43 per bbl for the six months ended June 30, 2021, an increase of 81% from US$33.33 per bbl for the six months ended June 30, 2020. The SCO price averaged US$66.49 per bbl for the second quarter of 2021, an increase of 186% from US$23.28 per bbl for the second quarter of 2020, and an increase of 22% from US$54.30 per bbl for the first quarter of 2021. The increase in SCO pricing for the three and six months ended June 30, 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing. The increase in SCO pricing for the second quarter of 2021 from the first quarter of 2021 also reflected reduced supply from the planned and unplanned turnarounds at various upgraders in Alberta during the second quarter of 2021.

NYMEX natural gas prices averaged US$2.76 per MMBtu for the six months ended June 30, 2021, an increase of 50% from US$1.84 per MMBtu for the six months ended June 30, 2020. NYMEX natural gas prices averaged US$2.83 per MMBtu for the second quarter of 2021, an increase of 65% from US$1.72 per MMBtu for the second quarter of 2020, and an increase of 5% from US$2.69 per MMBtu for the first quarter of 2021. The increase in NYMEX natural gas prices for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected increased North American demand in 2021 due to the impact of COVID-19 in 2020, as well as lower production levels. The increase in NYMEX natural gas prices for the second quarter of 2021 from the first quarter of 2021 primarily reflected increased Liquefied Natural Gas exports, together with low storage levels.

AECO natural gas prices averaged $2.74 per GJ for the six months ended June 30, 2021, an increase of 43% from $1.92 per GJ for the six months ended June 30, 2020. AECO natural gas prices averaged $2.70 per GJ for the second quarter of 2021, an increase of 49% from $1.81 per GJ for the second quarter of 2020, and comparable with $2.77 per GJ for the first quarter of 2021. The increase in AECO natural gas prices for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected lower storage levels and increased NYMEX benchmark pricing.

DAILY PRODUCTION, before royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**478,314**	478,736	413,506	**478,524**	435,191
North America – Oil Sands Mining and Upgrading [(1)]	**361,707**	468,803	464,318	**414,959**	451,210
North Sea	**16,458**	19,959	26,627	**18,199**	27,191
Offshore Africa	**16,239**	11,854	17,444	**14,059**	16,694
	872,718	979,352	921,895	**925,741**	930,286
Natural gas (MMcf/d)					
North America	**1,594**	1,585	1,431	**1,589**	1,419
North Sea	**4**	4	15	**4**	19
Offshore Africa	**16**	9	16	**13**	13
	1,614	1,598	1,462	**1,606**	1,451
Total barrels of oil equivalent (BOE/d)	**1,141,739**	1,245,703	1,165,487	**1,193,434**	1,172,120
Product mix					
Light and medium crude oil and NGLs	**11%**	10%	11%	**11%**	11%
Pelican Lake heavy crude oil	**5%**	4%	5%	**5%**	5%
Primary heavy crude oil	**6%**	5%	5%	**5%**	6%
Bitumen (thermal oil)	**23%**	22%	18%	**22%**	19%
Synthetic crude oil [(1)]	**32%**	38%	40%	**35%**	38%
Natural gas	**23%**	21%	21%	**22%**	21%
Percentage of gross revenue [(1)] [(2)] (excluding Midstream and Refining revenue)					
Crude oil and NGLs	**92%**	92%	89%	**92%**	91%
Natural gas	**8%**	8%	11%	**8%**	9%

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

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

DAILY PRODUCTION, net of royalties

	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**407,111**	422,124	379,554	**414,576**	397,007
North America – Oil Sands Mining and Upgrading	**331,214**	448,315	462,143	**389,441**	447,539
North Sea	**16,380**	19,927	26,567	**18,144**	27,130
Offshore Africa	**15,531**	11,325	16,739	**13,440**	16,017
	770,236	901,691	885,003	**835,601**	887,693
Natural gas (MMcf/d)					
North America	**1,532**	1,508	1,399	**1,521**	1,387
North Sea	**4**	4	15	**4**	19
Offshore Africa	**16**	9	15	**12**	12
	1,552	1,521	1,429	**1,537**	1,418
Total barrels of oil equivalent (BOE/d)	**1,028,908**	1,155,220	1,123,221	**1,091,716**	1,124,029

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, 2021 averaged 925,741 bbl/d, comparable with 930,286 bbl/d for the six months ended June 30, 2020. Crude oil and NGLs production for the second quarter of 2021 averaged 872,718 bbl/d, a decrease of 5% from 921,895 bbl/d for the second quarter of 2020, and a decrease of 11% from 979,352 bbl/d for the first quarter of 2021. The decrease in crude oil and NGLs production for the second quarter of 2021 from the second quarter of 2020 and the first quarter of 2021 primarily reflected the impact of the timing of the planned turnaround at Horizon and de-coking at the Scotford Upgrader ("Scotford"), which were both completed during the second quarter of 2021. Crude oil and NGLs production in North America Exploration and Production and Oil Sands Mining and Upgrading segments for the comparable periods in 2020 reflected the impact of the Company's curtailment optimization strategy during mandatory Government of Alberta curtailment.

Natural gas production before royalties for the six months ended June 30, 2021 of 1,606 MMcf/d increased 11% from 1,451 MMcf/d for the six months ended June 30, 2020. Natural gas production for the second quarter of 2021 of 1,614 MMcf/d increased 10% from 1,462 MMcf/d for the second quarter of 2020, and was comparable with 1,598 MMcf/d for the first quarter of 2021. The increase in natural gas production for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected production volumes from the acquisition in the fourth quarter of 2020 and strong drilling results, partially offset by natural field declines. Natural gas production in the first half of 2021 also reflected a decrease of approximately 75 MMcf/d due to the temporary shutdown of the Pine River Gas Plant. The plant resumed operations on July 24, 2021, restoring approximately 100 MMcf/d.

Annual crude oil and NGLs production for 2021 is now targeted to average between 940,000 bbl/d and 980,000 bbl/d. Annual natural gas production for 2021 is now targeted to average between 1,680 MMcf/d and 1,720 MMcf/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

North America – Exploration and Production

North America crude oil and NGLs production before royalties for the six months ended June 30, 2021 averaged 478,524 bbl/d, an increase of 10% from 435,191 bbl/d for the six months ended June 30, 2020. North America crude oil and NGLs production for the second quarter of 2021 of 478,314 bbl/d increased 16% from 413,506 bbl/d for the second quarter of 2020, and was comparable with 478,736 bbl/d for the first quarter of 2021. The increase in crude oil and NGLs production for the three and six months ended of June 30, 2021 from the comparable periods in 2020 primarily reflected the impact of the suspension of mandatory Government of Alberta curtailment on December 1, 2020.

Thermal oil production before royalties for the second quarter of 2021 averaged 258,551 bbl/d, an increase of 21% from 212,807 bbl/d for the second quarter of 2020, and a decrease of 3% from 267,530 bbl/d for the first quarter of 2021. The increase in thermal oil production for the second quarter of 2021 from the second quarter of 2020 reflected the impact of the Company's curtailment optimization strategy in the comparable period of 2020. Production in the second quarter of 2021 continued to reflect high utilization at Jackfish and Kirby North.

Pelican Lake heavy crude oil production before royalties averaged 55,212 bbl/d for the second quarter of 2021, comparable with 55,731 bbl/d for the second quarter of 2020, and 55,498 bbl/d for the first quarter of 2021, demonstrating Pelican Lake's long-life low decline production.

Natural gas production before royalties for the six months ended June 30, 2021 averaged 1,589 MMcf/d, an increase of 12% from 1,419 MMcf/d for the six months ended June 30, 2020. Natural gas production for the second quarter of 2021 averaged 1,594 MMcf/d, an increase of 11% from 1,431 MMcf/d for the second quarter of 2020, and was comparable with 1,585 MMcf/d for the first quarter of 2021. The increase in natural gas production for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected production volumes from the acquisition in the fourth quarter of 2020 and strong drilling results, partially offset by the impact of natural field declines. Natural gas production in the first half of 2021 also reflected a decrease of approximately 75 MMcf/d due to the temporary shutdown of the Pine River Gas Plant. The plant resumed operations on July 24, 2021, restoring approximately 100 MMcf/d.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the six months ended June 30, 2021 of 414,959 bbl/d decreased 8% from 451,210 bbl/d for the six months ended June 30, 2020. SCO production for the second quarter of 2021 of 361,707 bbl/d decreased 22% from 464,318 bbl/d for the second quarter of 2020 and decreased 23% from 468,803 bbl/d for the first quarter of 2021. The decrease in SCO production for the three and six months ended June 30, 2021 from the comparable periods primarily reflected the impact of the timing of the planned turnaround at Horizon and de-coking at Scotford, which were both completed during the second quarter of 2021.

North Sea

North Sea crude oil production before royalties for the six months ended June 30, 2021 of 18,199 bbl/d decreased 33% from 27,191 bbl/d for the six months ended June 30, 2020. North Sea crude oil production for the second quarter of 2021 of 16,458 bbl/d decreased 38% from 26,627 bbl/d for the second quarter of 2020 and decreased 18% from 19,959 bbl/d for the first quarter of 2021. The decrease in production for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected planned maintenance activities during the second quarter of 2021, natural field declines, and the permanent cessation of production at the Banff and Kyle fields in 2020. The decrease in production for the second quarter of 2021 from the first quarter of 2021 primarily reflected planned maintenance activities during the second quarter of 2021.

Offshore Africa

Offshore Africa crude oil production before royalties for the six months ended June 30, 2021 decreased 16% to 14,059 bbl/d from 16,694 bbl/d for the six months ended June 30, 2020. Offshore Africa crude oil production for the second quarter of 2021 of 16,239 bbl/d decreased 7% from 17,444 bbl/d for the second quarter of 2020 and increased 37% from 11,854 bbl/d for the first quarter of 2021. The decrease in production for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected maintenance activities during the first half of 2021 and natural field declines. The increase in production for the second quarter of 2021 from the first quarter of 2021 primarily reflected the completion of maintenance activities.

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 segments on crude oil volumes held in various storage facilities or FPSOs, as follows:

(bbl)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020
North Sea	**270,524**	—	190,135
Offshore Africa	**458,208**	612,242	1,375,747
	728,732	612,242	1,565,882

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs ($/bbl) (1)					
Sales price (2)	**$ 61.20**	$ 52.68	$ 18.97	**$ 56.87**	$ 22.70
Transportation	**3.98**	3.56	4.20	**3.77**	4.02
Realized sales price, net of transportation	**57.22**	49.12	14.77	**53.10**	18.68
Royalties	**8.50**	5.69	1.48	**7.07**	1.94
Production expense	**13.75**	14.56	12.53	**14.16**	13.17
Netback	**$ 34.97**	$ 28.87	$ 0.76	**$ 31.87**	$ 3.57
Natural gas ($/Mcf) (1)					
Sales price (2)	**$ 3.17**	$ 3.42	$ 2.03	**$ 3.29**	$ 2.13
Transportation	**0.48**	0.46	0.41	**0.47**	0.44
Realized sales price, net of transportation	**2.69**	2.96	1.62	**2.82**	1.69
Royalties	**0.12**	0.16	0.05	**0.14**	0.05
Production expense	**1.19**	1.27	1.15	**1.23**	1.23
Netback	**$ 1.38**	$ 1.53	$ 0.42	**$ 1.45**	$ 0.41
Barrels of oil equivalent ($/BOE) (1)					
Sales price (2)	**$ 46.40**	$ 41.80	$ 16.57	**$ 44.08**	$ 19.37
Transportation	**3.58**	3.29	3.61	**3.42**	3.55
Realized sales price, net of transportation	**42.82**	38.51	12.96	**40.66**	15.82
Royalties	**5.77**	4.10	1.05	**4.93**	1.40
Production expense	**11.42**	12.20	10.55	**11.82**	11.24
Netback	**$ 25.63**	$ 22.21	$ 1.36	**$ 23.91**	$ 3.18

(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 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs ($/bbl) (1) (2)					
North America	**$ 59.80**	$ 50.67	$ 17.22	**$ 55.21**	$ 20.57
North Sea	**$ 85.09**	$ 75.16	$ 45.60	**$ 77.48**	$ 45.74
Offshore Africa	**$ 85.78**	$ 80.00	$ 29.40	**$ 83.62**	$ 48.35
Average	**$ 61.20**	$ 52.68	$ 18.97	**$ 56.87**	$ 22.70
Natural gas ($/Mcf) (1) (2)					
North America	**$ 3.13**	$ 3.41	$ 1.97	**$ 3.27**	$ 2.06
North Sea	**$ 2.58**	$ 2.57	$ 1.42	**$ 2.57**	$ 2.81
Offshore Africa	**$ 6.50**	$ 6.09	$ 8.75	**$ 6.35**	$ 8.83
Average	**$ 3.17**	$ 3.42	$ 2.03	**$ 3.29**	$ 2.13
Average ($/BOE) (1) (2)	**$ 46.40**	$ 41.80	$ 16.57	**$ 44.08**	$ 19.37

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

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

North America

North America realized crude oil prices increased 168% to average $55.21 per bbl for the six months ended June 30, 2021 from $20.57 per bbl for the six months ended June 30, 2020. North America realized crude oil prices increased 247% to average $59.80 per bbl for the second quarter of 2021 from $17.22 per bbl for the second quarter of 2020, and increased 18% from $50.67 per bbl for the first quarter of 2021. The increase in realized crude oil prices for the three and six months ended June 30, 2021 from the comparable periods was primarily due to higher WTI benchmark pricing, together with the narrowing of the WCS Heavy Differential. The Company continues to focus on its crude oil blending marketing strategy and in the second quarter of 2021 contributed approximately 131,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 59% to average $3.27 per Mcf for the six months ended June 30, 2021 from $2.06 per Mcf for the six months ended June 30, 2020. North America realized natural gas prices increased 59% to average $3.13 per Mcf for the second quarter of 2021 from $1.97 per Mcf for the second quarter of 2020, and decreased 8% from $3.41 per Mcf for the first quarter of 2021. The increase in realized natural gas prices for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected lower storage levels and increased benchmark pricing. The decrease in realized natural gas prices for the second quarter of 2021 from the first quarter of 2021 primarily reflected seasonal demand factors.

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

	Three Months Ended		
(Quarterly average)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020
Wellhead Price (1) (2)			
Light and medium crude oil and NGLs ($/bbl)	**$ 55.81**	$ 50.54	$ 20.36
Pelican Lake heavy crude oil ($/bbl)	**$ 67.75**	$ 55.26	$ 20.98
Primary heavy crude oil ($/bbl)	**$ 64.24**	$ 54.24	$ 17.98
Bitumen (thermal oil) ($/bbl)	**$ 58.50**	$ 48.92	$ 14.79
Natural gas ($/Mcf)	**$ 3.13**	$ 3.41	$ 1.97

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

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

North Sea

North Sea realized crude oil prices increased 69% to average $77.48 per bbl for the six months ended June 30, 2021 from $45.74 per bbl for the six months ended June 30, 2020. North Sea realized crude oil prices increased 87% to average $85.09 per bbl for the second quarter of 2021 from $45.60 per bbl for the second quarter of 2020 and increased 13% from $75.16 per bbl for the first quarter of 2021. 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, 2021 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

Offshore Africa

Offshore Africa realized crude oil prices increased 73% to average $83.62 per bbl for the six months ended June 30, 2021 from $48.35 per bbl for the six months ended June 30, 2020. Offshore Africa realized crude oil prices increased 192% to average $85.78 per bbl for the second quarter of 2021 from $29.40 per bbl for the second quarter of 2020 and increased 7% from $80.00 per bbl for the first quarter of 2021. 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, 2021 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 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 8.84**	$ 6.09	$ 1.56	**$ 7.46**	$ 2.06
North Sea	**$ 0.39**	$ 0.12	$ 0.10	**$ 0.18**	$ 0.10
Offshore Africa	**$ 3.74**	$ 3.57	$ 1.19	**$ 3.68**	$ 1.96
Average	**$ 8.50**	$ 5.69	$ 1.48	**$ 7.07**	$ 1.94
Natural gas ($/Mcf) (1)					
North America	**$ 0.12**	$ 0.16	$ 0.04	**$ 0.14**	$ 0.05
Offshore Africa	**$ 0.30**	$ 0.28	$ 0.40	**$ 0.29**	$ 0.44
Average	**$ 0.12**	$ 0.16	$ 0.05	**$ 0.14**	$ 0.05
Average ($/BOE) (1)	**$ 5.77**	$ 4.10	$ 1.05	**$ 4.93**	$ 1.40

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

North America

North America crude oil and natural gas royalties for the three and six months ended June 30, 2021 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 14% of product sales for the six months ended June 30, 2021 compared with 10% of product sales for the six months ended June 30, 2020. Crude oil and NGLs royalty rates averaged approximately 15% of product sales for the second quarter of 2021 compared with 9% for the second quarter of 2020 and 12% for the first quarter of 2021. The increase in royalty rates for the three and six months ended June 30, 2021 from the comparable periods was primarily due to higher benchmark prices together with fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 4% of product sales for the six months ended June 30, 2021 compared with 2% of product sales for the six months ended June 30, 2020. Natural gas royalty rates averaged approximately 4% of product sales for the second quarter of 2021 compared with 2% for the second quarter of 2020 and 5% for the first quarter of 2021. The increase in royalty rates for the three and six months ended June 30, 2021 from the comparable periods in 2020 was primarily due to higher benchmark prices. The decrease in royalty rates for the second quarter of 2021 from the first quarter of 2021 primarily reflected lower realized natural gas prices in the second quarter of 2021.

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, 2021, comparable with 4% of product sales for the six months ended June 30, 2020. Royalty rates as a percentage of product sales averaged approximately 4% for the second quarter of 2021 comparable with 4% of product sales for the second quarter of 2020 and 4% for the first quarter of 2021. 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 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.82**	$ 12.80	$ 11.65	**$ 12.81**	$ 12.20
North Sea	**$ 63.65**	$ 42.24	$ 28.47	**$ 47.25**	$ 29.19
Offshore Africa	**$ 13.20**	$ 16.57	$ 10.62	**$ 14.46**	$ 11.45
Average	**$ 13.75**	$ 14.56	$ 12.53	**$ 14.16**	$ 13.17
Natural gas ($/Mcf) (1)					
North America	**$ 1.15**	$ 1.24	$ 1.11	**$ 1.20**	$ 1.17
North Sea	**$ 6.96**	$ 4.85	$ 3.18	**$ 5.97**	$ 3.34
Offshore Africa	**$ 3.37**	$ 4.99	$ 3.46	**$ 3.97**	$ 4.30
Average	**$ 1.19**	$ 1.27	$ 1.15	**$ 1.23**	$ 1.23
Average ($/BOE) (1)	**$ 11.42**	$ 12.20	$ 10.55	**$ 11.82**	$ 11.24

(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, 2021 averaged $12.81 per bbl, an increase of 5% from $12.20 per bbl for the six months ended June 30, 2020. North America crude oil and NGLs production expense for the second quarter of 2021 of $12.82 per bbl increased 10% from $11.65 per bbl for the second quarter of 2020 and was comparable with $12.80 per bbl for the first quarter of 2021. The increase in crude oil and NGLs production expense per bbl for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected an increase in energy costs in 2021.

North America natural gas production expense for the six months ended June 30, 2021 averaged $1.20 per Mcf, comparable with $1.17 per Mcf for the six months ended June 30, 2020. North America natural gas production expense for the second quarter of 2021 of $1.15 per Mcf increased 4% from $1.11 per Mcf for the second quarter of 2020 and decreased 7% from $1.24 per Mcf for the first quarter of 2021. Natural gas production expense per Mcf for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected the impact of an increase in electricity costs, offsetting the Company's continuous focus on cost control. The decrease in natural gas production expense per Mcf for the second quarter of 2021 from the first quarter of 2021 primarily reflected the impact of seasonality.

North Sea

North Sea crude oil production expense for the six months ended June 30, 2021 averaged $47.25 per bbl, an increase of 62% from $29.19 per bbl for the six months ended June 30, 2020. North Sea crude oil production expense for the second quarter of 2021 of $63.65 per bbl increased from $28.47 per bbl for the second quarter of 2020 and increased 51% from $42.24 per bbl for the first quarter of 2021. The increase in crude oil production expense per bbl for the three and six months ended June 30, 2021 from the comparable periods was primarily due to lower volumes due to maintenance activities on a relatively fixed cost base. The increase from the comparable periods in 2020 also reflected higher energy costs. 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, 2021 averaged $14.46 per bbl, an increase of 26% from $11.45 per bbl for the six months ended June 30, 2020. Offshore Africa crude oil production expense for the second quarter of 2021 of $13.20 per bbl increased 24% from $10.62 per bbl for the second quarter of 2020 and decreased 20% from $16.57 per bbl for the first quarter of 2021. The fluctuations in crude oil production expense per bbl for the three and six months ended June 30, 2021 from the comparable periods were primarily due to the timing of liftings from various fields that have different cost structures and fluctuating volumes due to maintenance activities, on a relatively fixed cost base. Offshore Africa production expense also reflected fluctuations in the Canadian dollar.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
North America	**$ 881**	$ 868	$ 871	**$ 1,749**	$ 1,826
North Sea	**19**	68	76	**87**	175
Offshore Africa	**44**	31	27	**75**	68
Expense	**$ 944**	$ 967	$ 974	**$ 1,911**	$ 2,069
$/BOE (1)	**$ 13.57**	$ 13.70	$ 15.47	**$ 13.63**	$ 15.62

(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, 2021 of $13.63 per BOE decreased 13% from $15.62 per BOE for the six months ended June 30, 2020. Depletion, depreciation and amortization expense for the second quarter of 2021 of $13.57 per BOE decreased 12% from $15.47 per BOE for the second quarter of 2020 and was comparable with $13.70 per BOE for the first quarter of 2021. The decrease in depletion, depreciation and amortization expense per BOE for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected lower depletion rates in the North America Exploration and Production segment, including the impact of the acquisition in the fourth quarter of 2020.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
North America	**$ 25**	$ 25	$ 23	**$ 50**	$ 50
North Sea	**5**	5	8	**10**	15
Offshore Africa	**2**	1	2	**3**	3
Expense	**$ 32**	$ 31	$ 33	**$ 63**	$ 68
$/BOE (1)	**$ 0.46**	$ 0.45	$ 0.53	**$ 0.45**	$ 0.51

(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, 2021 of $0.45 per BOE decreased 12% from $0.51 per BOE for the six months ended June 30, 2020. Asset retirement obligation accretion expense for the second quarter of 2021 of $0.46 per BOE decreased 13% from $0.53 per BOE for the second quarter of 2020 and was comparable with $0.45 per BOE for the first quarter of 2021. 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. SCO production in the second quarter of 2021 of 361,707 bbl/d reflected the impact of the timing of the planned turnaround at Horizon and de-coking at Scotford, which were both completed during the second quarter of 2021.

The Company incurred production costs, excluding natural gas costs, of $799 million ($23.94 per bbl) for the second quarter of 2021, a 3% increase (30% increase per bbl) from the first quarter of 2021.

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

($/bbl) (1)	Three Months Ended			Six Months Ended	
	Jun 30 2021	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
SCO realized sales price (2)	**$ 76.19**	$ 64.60	$ 29.11	**$ 69.71**	$ 39.71
Bitumen value for royalty purposes (3)	**$ 58.46**	$ 46.39	$ 18.35	**$ 51.75**	$ 17.60
Bitumen royalties (4)	**$ 5.92**	$ 2.88	$ 0.15	**$ 4.22**	$ 0.50
Transportation	**$ 1.26**	$ 1.10	$ 0.97	**$ 1.17**	$ 1.12

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

(2) Net of blending and feedstock costs.

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

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

The realized SCO sales price averaged $69.71 per bbl for the six months ended June 30, 2021, an increase of 76% from $39.71 per bbl for the six months ended June 30, 2020. The realized SCO sales price averaged $76.19 per bbl for the second quarter of 2021, an increase of 162% from $29.11 per bbl for the second quarter of 2020 and an increase of 18% from $64.60 per bbl for the first quarter of 2021. The increase in the realized SCO sales price for the three and six months ended June 30, 2021 from the comparable periods primarily reflected increases in WTI benchmark pricing. The increase in the realized SCO sales price for the second quarter of 2021 from the first quarter of 2021 also reflected reduced supply from the planned and unplanned turnarounds at various upgraders in Alberta during the second quarter of 2021.

Transportation expense averaged $1.17 per bbl for the six months ended June 30, 2021, an increase of 4% from $1.12 per bbl for the six months ended June 30, 2020. For the second quarter of 2021, transportation expense of $1.26 per bbl increased 30% from $0.97 per bbl for the second quarter of 2020 and increased 15% from $1.10 per bbl for the first quarter of 2021. The increase in transportation expense per bbl for the second quarter of 2021 from the second quarter of 2020 and the first quarter of 2021 primarily reflected the impact of lower sales volumes at Horizon during the second quarter of 2021.

PRODUCTION COSTS – OIL SANDS MINING AND UPGRADING

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

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Production costs, excluding natural gas costs	**$ 799**	$ 779	$ 699	**$ 1,578**	$ 1,472
Natural gas costs	**51**	59	31	**110**	67
Production costs	**$ 850**	$ 838	$ 730	**$ 1,688**	$ 1,539

	Three Months Ended			Six Months Ended	
($/bbl) (1)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Production costs, excluding natural gas costs	**$ 23.94**	$ 18.42	$ 16.98	**$ 20.86**	$ 18.37
Natural gas costs	**1.52**	1.40	0.76	**1.45**	0.84
Production costs	**$ 25.46**	$ 19.82	$ 17.74	**$ 22.31**	$ 19.21
Sales (bbl/d)	**366,843**	469,953	452,066	**418,113**	440,290

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

Production costs for the six months ended June 30, 2021 increased 16% to $22.31 per bbl from $19.21 per bbl for the six months ended June 30, 2020. Production costs for the second quarter of 2021 averaged $25.46 per bbl, an increase of 44% from $17.74 per bbl for the second quarter of 2020 and an increase of 28% from $19.82 per bbl for the first quarter of 2021. The increase in production costs per bbl for the three and six months ended June 30, 2021 from the comparable periods in 2020 primarily reflected lower production volumes and higher production expenses due to the impact of the timing of the planned turnaround at Horizon and de-coking at Scotford, together with the impact of higher energy costs, including natural gas costs. The increase in production costs per bbl for the second quarter of 2021 from the first quarter of 2021 primarily reflected the impact of the timing of the planned turnaround at Horizon and de-coking at Scotford, which were both completed during the second quarter of 2021. 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 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Expense	**$ 441**	$ 450	$ 451	**$ 891**	$ 891
$/bbl (1)	**$ 13.20**	$ 10.64	$ 10.97	**$ 11.77**	$ 11.12

(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, 2021 of $11.77 per bbl increased 6% from $11.12 per bbl for the six months ended June 30, 2020. Depletion, depreciation and amortization expense for the second quarter of 2021 of $13.20 per bbl increased 20% from $10.97 per bbl for the second quarter of 2020, and increased 24% from $10.64 per bbl for the first quarter of 2021. The increase in depletion, depreciation and amortization on a per barrel basis for the three and six months ended June 30, 2021 from the comparable periods primarily reflected the impact of lower sales volumes and minor asset derecognitions at Horizon during the second quarter of 2021.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended						Six Months Ended			
($ millions, except per bbl amounts)		**Jun 30 2021**		Mar 31 2021		Jun 30 2020		**Jun 30 2021**		Jun 30 2020
Expense	**$**	**14**	$	15	$	18	**$**	**29**	$	35
$/bbl [1]	**$**	**0.43**	$	0.34	$	0.44	**$**	**0.38**	$	0.44

(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, 2021 of $0.38 per bbl decreased 14% from $0.44 per bbl for the six months ended June 30, 2020. Asset retirement obligation accretion expense of $0.43 per bbl for the second quarter of 2021 was comparable with $0.44 per bbl for the second quarter of 2020 and increased 26% from $0.34 per bbl for the first quarter of 2021. Fluctuations in asset retirement obligation accretion expense on a per barrel basis primarily reflect fluctuating sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended						Six Months Ended			
($ millions)		**Jun 30 2021**		Mar 31 2021		Jun 30 2020		**Jun 30 2021**		Jun 30 2020
Product sales										
Midstream activities	**$**	**21**	$	19	$	20	**$**	**40**	$	41
NWRP, refined product sales and other		**171**		131		25		**302**		25
Segmented revenue		**192**		150		45		**342**		66
Less:										
Production expense										
NWRP, refining toll		**72**		58		24		**130**		24
Midstream activities		**7**		5		5		**12**		11
NWRP, transportation and feedstock costs		**134**		105		22		**239**		22
Depreciation		**3**		4		3		**7**		7
Income from NWRP		**(400)**		—		—		**(400)**		—
Segmented earnings (loss) before taxes	**$**	**376**	$	(22)	$	(9)	**$**	**354**	$	2

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% equity investment in NWRP.

NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that processes approximately 12,500 barrels per day (25% toll payer) of bitumen feedstock for the Company and 37,500 barrels per day (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the second quarter of 2021, production of ultra-low sulphur diesel and other refined products averaged 73,465 BOE/d (18,366 BOE/d to the Company).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP.

As at June 30, 2021, the cumulative unrecognized share of the equity loss from NWRP of $129 million and total partnership distributions in excess of the cumulative share of equity income, was $529 million (December 31, 2020 – $153 million; June 30, 2020 – $175 million). For the three months ended June 30, 2021, unrecognized equity income was $7 million, (six months ended June 30, 2021 – unrecognized equity income of $24 million; three months ended June 30, 2020 – unrecognized equity loss of $23 million; six months ended June 30, 2020 – unrecognized equity loss of $116 million).

ADMINISTRATION EXPENSE

	Three Months Ended			Six Months Ended	
($ millions, except per BOE amounts)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Expense	**$ 87**	$ 95	$ 88	**$ 182**	$ 196
$/BOE (1)	**$ 0.84**	$ 0.84	$ 0.84	**$ 0.84**	$ 0.92

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

Administration expense for the six months ended June 30, 2021 of $0.84 per BOE decreased 9% from $0.92 per BOE for the six months ended June 30, 2020. Administration expense for the second quarter of 2021 of $0.84 per BOE was comparable with $0.84 per BOE for the second quarter of 2020 and the first quarter of 2021. Administration expense per BOE decreased for the six months ended June 30, 2021 from the six months ended June 30, 2020 primarily due to higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Expense (recovery)	**$ 137**	$ 129	$ 23	**$ 266**	$ (200)

The Company's Stock Option Plan provides 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 recognized a $266 million share-based compensation expense for the six months ended June 30, 2021, primarily as a result of the measurement of the fair value of outstanding stock options related to the impact of normal course graded vesting of stock options granted in prior periods, the impact of vested stock options exercised or surrendered during the period, and changes in the Company's share price. Included within the share-based compensation expense for the six months ended June 30, 2021 was an expense of $35 million related to PSUs granted to certain executive employees (June 30, 2020 – $6 million recovery). For the six months ended June 30, 2021, the Company charged $2 million of share-based compensation costs to the Oil Sands Mining and Upgrading segment (June 30, 2020 – $3 million charged).

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except per BOE amounts and interest rates)	Three Months Ended Jun 30 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
Expense, gross	**$ 177**	$ 185	$ 206	**$ 362**	$ 420
Less: capitalized interest	**—**	—	7	**—**	15
Expense, net	**$ 177**	$ 185	$ 199	**$ 362**	$ 405
$/BOE (1)	**$ 1.73**	$ 1.64	$ 1.91	**$ 1.68**	$ 1.90
Average effective interest rate	**3.5%**	3.4%	3.5%	**3.4%**	3.7%

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

Net interest and other financing expense per BOE for the six months ended June 30, 2021 decreased 12% to $1.68 per BOE from $1.90 per BOE for the six months ended June 30, 2020. Net interest and other financing expense per BOE for the second quarter of 2021 decreased 9% to $1.73 per BOE from $1.91 per BOE for the second quarter of 2020 and increased 5% from $1.64 per BOE for the first quarter of 2021. The decrease in interest expense and other financing expense per BOE for the three and six months ended June 30, 2021 from the comparable periods in 2020 was primarily due to lower average debt levels and lower average interest rates in 2021. The increase in interest expense per BOE for the second quarter of 2021 from the first quarter of 2021 was primarily due to lower sales volumes in the second quarter of 2021.

The Company's average effective interest rate for the second quarter of 2021 was comparable with the first quarter of 2021.

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 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
Foreign currency contracts	**$ 15**	$ 15	$ 28	**$ 30**	$ (29)
Natural gas financial instruments	**3**	(6)	3	**(3)**	13
Net realized loss (gain)	**18**	9	31	**27**	(16)
Foreign currency contracts	**(4)**	(5)	—	**(9)**	(9)
Natural gas financial instruments	**14**	25	1	**39**	(7)
Net unrealized loss (gain)	**10**	20	1	**30**	(16)
Net loss (gain)	**$ 28**	$ 29	$ 32	**$ 57**	$ (32)

During the six months ended June 30, 2021, net realized risk management losses were related to the settlement of foreign currency contracts, partially offset by gains on the settlement of natural gas financial instruments. The Company recorded a net unrealized loss of $30 million ($21 million after-tax) on its risk management activities for the six months ended June 30, 2021, including an unrealized loss of $10 million ($6 million after-tax) for the second quarter of 2021 (March 31, 2021 – unrealized loss of $20 million, $15 million after-tax; June 30, 2020 – unrealized loss of $1 million, $1 million after-tax).

Further details related to outstanding derivative financial instruments at June 30, 2021 are disclosed in note 15 to the Company's unaudited interim consolidated financial statements.

FOREIGN EXCHANGE

($ millions)	Three Months Ended Jun 30 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
Net realized loss (gain)	**$ 11**	$ 10	$ 3	**$ 21**	$ (196)
Net unrealized (gain) loss	**(151)**	(172)	(433)	**(323)**	688
Net (gain) loss (1)	**$ (140)**	$ (162)	$ (430)	**$ (302)**	$ 492

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

The net realized foreign exchange loss for the six months ended June 30, 2021 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the six months ended June 30, 2021 was primarily related to the impact of a stronger Canadian dollar with respect to outstanding US dollar debt. The net unrealized (gain) loss for each of the periods presented 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, 2021 – unrealized loss of $9 million, March 31, 2021 – unrealized loss of $10 million, June 30, 2020 – unrealized loss of $28 million; six months ended June 30, 2021 – unrealized loss of $19 million, June 30, 2020 – unrealized loss of $102 million). The US/Canadian dollar exchange rate at June 30, 2021 was US$0.8062 (March 31, 2021 – US$0.7954, June 30, 2020 – US$0.7345).

INCOME TAXES

($ millions, except income tax rates)	Three Months Ended Jun 30 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
North America (1)	**$ 324**	$ 285	$ (34)	**$ 609**	$ (228)
North Sea	**(5)**	11	1	**6**	10
Offshore Africa	**7**	4	2	**11**	6
PRT (2) – North Sea	**(12)**	(5)	—	**(17)**	—
Other taxes	**3**	2	—	**5**	2
Current income tax expense (recovery)	**317**	297	(31)	**614**	(210)
Deferred income tax expense (recovery)	**129**	21	(267)	**150**	(247)
	$ 446	$ 318	$ (298)	**$ 764**	$ (457)
Effective income tax rate on adjusted net earnings (loss) from operations (3)	**24%**	21%	28%	**23%**	30%

(1) Includes North America Exploration and Production, Oil Sands Mining and Upgrading, and Midstream and Refining 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, 2021 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings (loss).

The current corporate income tax and PRT in the North Sea for the three and six months ended June 30, 2021 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.

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 2021**	Three Months Ended Mar 31 2021	Three Months Ended Jun 30 2020	Six Months Ended **Jun 30 2021**	Six Months Ended Jun 30 2020
Exploration and Evaluation					
Net property dispositions	**$ (4)**	$ —	$ —	**$ (4)**	$ (18)
Net expenditures	**1**	4	1	**5**	26
Total Exploration and Evaluation	**(3)**	4	1	**1**	8
Property, Plant and Equipment					
Net property acquisitions	**7**	1	2	**8**	15
Well drilling, completion and equipping	**224**	266	32	**490**	234
Production and related facilities	**186**	192	78	**378**	292
Other	**16**	13	14	**29**	26
Total Property, Plant and Equipment	**433**	472	126	**905**	567
Total Exploration and Production	**430**	476	127	**906**	575
Oil Sands Mining and Upgrading					
Project costs	**61**	41	49	**102**	105
Sustaining capital	**346**	186	172	**532**	373
Turnaround costs	**74**	29	20	**103**	43
Other [2]	**326**	1	9	**327**	18
Total Oil Sands Mining and Upgrading	**807**	257	250	**1,064**	539
Midstream and Refining	**1**	2	2	**3**	3
Abandonments [3]	**44**	67	40	**111**	129
Head office	**3**	6	2	**9**	13
Total net capital expenditures	**$ 1,285**	$ 808	$ 421	**$ 2,093**	$ 1,259
By segment					
North America	**$ 378**	$ 419	$ 95	**$ 797**	$ 490
North Sea	**44**	32	17	**76**	43
Offshore Africa	**8**	25	15	**33**	42
Oil Sands Mining and Upgrading	**807**	257	250	**1,064**	539
Midstream and Refining	**1**	2	2	**3**	3
Abandonments [3]	**44**	67	40	**111**	129
Head office	**3**	6	2	**9**	13
Total	**$ 1,285**	$ 808	$ 421	**$ 2,093**	$ 1,259

(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 the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 2021.

(3) Abandonments represent expenditures to settle asset retirement obligations and have been reflected as capital expenditures in this table and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

Net Capital Expenditures, as Reconciled to Cash Flows used in Investing Activities

	Three Months Ended			Six Months Ended	
($ millions)	**Jun 30 2021**	Mar 31 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Cash flows used in investing activities	***$ 719***	*$ 648*	*$ 693*	***$ 1,367***	*$ 1,552*
Net change in non-cash working capital	***(33)***	*93*	*(312)*	***60***	*(422)*
Repayment of NWRP subordinated debt advances	***555***	—	—	***555***	—
Abandonment expenditures (1)	***44***	*67*	*40*	***111***	*129*
Net capital expenditures	***$ 1,285***	*$ 808*	*$ 421*	***$ 2,093***	*$ 1,259*

(1) The Company excludes abandonment expenditures from "Adjusted Funds Flow, as Reconciled to Cash Flows from (used in) Operating Activities" in the "Financial Highlights" section of this MD&A and are net of the impact of government grant income under the provincial well-site rehabilitation programs.

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, 2021 were $2,093 million compared with $1,259 million for the six months ended June 30, 2020. Net capital expenditures for the second quarter of 2021 were $1,285 million compared with $421 million for the second quarter of 2020 and $808 million for the first quarter of 2021.

Year to date in 2021 to the end of July, the Company has completed three opportunistic acquisitions. The first two acquisitions consisted of natural gas assets located in the Montney region of British Columbia, with aggregate production of approximately 11,100 BOE/d, consisting of 63 MMcf/d and 600 bbl/d of NGLs, approximately 107,000 acres of Montney lands, and related processing infrastructure with approximately 140 MMcf/d of capacity. These two acquisitions build on the Company's expansive natural gas operations in northeastern British Columbia, increasing the Company's total Montney lands to approximately 1.3 million acres. The third acquisition consisted of a net carried interest on an existing Canadian Natural oil sands lease, from which all of the Company's current Horizon volumes are derived. Total cash consideration paid for these acquisitions was approximately $450 million, and the Company's 2021 capital budget will increase by this amount.

2021 Capital Budget

On December 9, 2020, the Company announced its 2021 capital budget targeted at approximately $3,205 million, of which $1,345 million is related to conventional and unconventional assets and $1,860 million is allocated to long-life low decline assets.

As discussed on page 9 in the "Business Environment" section of this MD&A, the Company targets to increase its 2021 capital budget, excluding acquisitions, to approximately $3,480 million, including approximate additions of $120 million related to conventional and unconventional assets, $110 million related to long-life low decline assets, and an additional $45 million related to abandonment and reclamation activities. The 2021 capital budget and production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity [(1)]

(number of net wells)	Three Months Ended Jun 30 2021	Mar 31 2021	Jun 30 2020	Six Months Ended Jun 30 2021	Jun 30 2020
Net successful natural gas wells	**9**	22	1	**31**	12
Net successful crude oil wells [(2)]	**27**	44	2	**71**	37
Stratigraphic test / service wells	**1**	328	4	**329**	371
Total	**37**	394	7	**431**	420
Success rate (excluding stratigraphic test / service wells)	**100%**	100%	100%	**100%**	100%

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

(2) Includes bitumen wells.

North America

During the second quarter of 2021, the Company targeted 9 net natural gas wells, 7 net primary heavy crude oil wells, 10 net Pelican Lake heavy crude oil wells, 4 net bitumen (thermal oil) wells and 5 net light crude oil wells.

North Sea

During the second quarter of 2021, the Company targeted 1 net light crude oil well in the North Sea.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Jun 30 2021	Mar 31 2021	Dec 31 2020	Jun 30 2020
Working capital [(1)]	**$ 723**	$ 626	$ 626	$ 993
Long-term debt [(2) (3)]	**$ 18,331**	$ 20,009	$ 21,453	$ 23,020
Less: cash and cash equivalents	**168**	166	184	233
Long-term debt, net	**$ 18,163**	$ 19,843	$ 21,269	$ 22,787
Share capital	**$ 9,863**	$ 9,685	$ 9,606	$ 9,521
Retained earnings	**24,390**	23,567	22,766	22,614
Accumulated other comprehensive income	**(46)**	(21)	8	198
Shareholders' equity	**$ 34,207**	$ 33,231	$ 32,380	$ 32,333
Debt to book capitalization [(3) (4)]	**34.7%**	37.4%	39.6%	41.3%
Debt to market capitalization [(3) (5)]	**25.4%**	30.1%	37.0%	45.0%
After-tax return on average common shareholders' equity [(6)]	**12.4%**	6.8%	(1.3)%	0.1%
After-tax return on average capital employed [(3) (7)]	**8.6%**	5.1%	0.2%	1.2%

(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 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 (defined as current and long-term debt plus shareholders' equity) for the twelve month trailing period.

As at June 30, 2021, 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, 2020. 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 its internally generated cash flows from operating activities supported by the implementation of its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short, medium and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of maintenance and growth capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
    - During the first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.
    - During 2019, the Company entered into a $3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon Canada Corporation. During the second quarter of 2021, the outstanding balance of $2,125 million was repaid and the facility was cancelled.
    - As at June 30, 2021, the Company had $2,200 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada. Subsequent to June 30, 2021, 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 2023, replacing the Company's previous base shelf prospectus, which would have expired 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.
    - As at June 30, 2021, the Company had US$1,900 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States. Subsequent to June 30, 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2023, replacing the Company's previous base shelf prospectus, which would have expired 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. Subsequent to June 30, 2021, the Company filed a notice for the early repayment of US$500 million of 3.45% debt securities in August 2021, originally due November 2021.
    - 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, 2021, the non-revolving term credit facilities were fully drawn.
    - 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.

- 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.

As at June 30, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Including cash and cash equivalents and short-term investments, the Company had approximately $5,596 million in liquidity. Additionally, the Company had in place fully drawn term credit facilities of $3,650 million. The Company also has certain other dedicated credit facilities supporting letters of credit. At June 30, 2021, the Company had $682 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

As at June 30, 2021, the Company had total US dollar denominated debt with a carrying amount of $15,224 million (US$12,273 million), before transaction costs and original issue discounts. This included $5,052 million (US$4,073 million) hedged by way of a cross currency swap (US$550 million) and foreign currency forwards (US$3,523 million). The fixed repayment amount of these hedging instruments is $4,946 million, resulting in a notional reduction of the carrying amount of the Company's US dollar denominated debt by approximately $106 million to $15,118 million as at June 30, 2021.

Net long-term debt was $18,163 million at June 30, 2021, resulting in a debt to book capitalization ratio of 34.7% (December 31, 2020 – 39.6%); this ratio is within the 25% to 45% internal range utilized by management. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flows from operating activities are greater than current investment activities. The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt at June 30, 2021 are discussed in note 8 of the Company's unaudited interim consolidated financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at June 30, 2021, 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. Further details related to the Company's commodity derivative financial instruments outstanding at June 30, 2021 are discussed in note 15 of the Company's unaudited interim consolidated financial statements.

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

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [(1)]	$ 2,300	$ 4,931	$ 3,109	$ 8,084
Other long-term liabilities [(2)]	$ 250	$ 189	$ 414	$ 877
Interest and other financing expense [(3)]	$ 694	$ 629	$ 1,505	$ 4,123

(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, $186 million; one to less than two years, $153 million; two to less than five years, $403 million; and thereafter, $877 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, 2021.

Share Capital

As at June 30, 2021, there were 1,185,595,000 common shares outstanding (December 31, 2020 – 1,183,866,000 common shares) and 50,156,000 stock options outstanding. As at August 3, 2021, the Company had 1,180,683,000 common shares outstanding and 49,604,000 stock options outstanding.

On March 3, 2021, the Board of Directors approved an increase in the quarterly dividend to $0.47 per common share, beginning with the dividend payable on April 5, 2021 (previous quarterly dividend rate of $0.425 per common share). The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 9, 2021, 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 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the six months ended June 30, 2021, the Company purchased 5,640,000 common shares at a weighted average price of $41.89 per common share for a total cost of $236 million. Retained earnings were reduced by $190 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2021, the Company purchased 5,404,400 common shares at a weighted average price of $42.12 per common share for a total cost of $228 million.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at June 30, 2021:

($ millions)	Remaining 2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1)	$ 442	$ 838	$ 907	$ 846	$ 811	$ 10,360
North West Redwater Partnership service toll (2)	$ 63	$ 123	$ 123	$ 122	$ 119	$ 3,784
Offshore vessels and equipment	$ 33	$ 41	$ —	$ —	$ —	$ —
Field equipment and power	$ 14	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 14	$ 21	$ 20	$ 21	$ 21	$ 16

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,546 million of interest payable over the 40-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.

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, 2021, COVID-19 continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the second quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. 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, 2020.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the six months ended June 30, 2021 that have materially affected, or are reasonably likely to materially affect the Company's ICFR. Due to 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 2021	Dec 31 2020
ASSETS			
Current assets			
Cash and cash equivalents		$ 168	$ 184
Accounts receivable		3,184	2,190
Current income taxes receivable		—	309
Inventory		1,214	1,060
Prepaids and other		325	231
Investments	6	469	305
Current portion of other long-term assets	7	124	82
		5,484	4,361
Exploration and evaluation assets	3	2,406	2,436
Property, plant and equipment	4	64,993	65,752
Lease assets	5	1,565	1,645
Other long-term assets	7	579	1,082
		$ 75,027	$ 75,276
LIABILITIES			
Current liabilities			
Accounts payable		$ 783	$ 667
Accrued liabilities		2,889	2,346
Current income taxes payable		371	—
Current portion of long-term debt	8	2,300	1,343
Current portion of other long-term liabilities	5,9	718	722
		7,061	5,078
Long-term debt	8	16,031	20,110
Other long-term liabilities	5,9	7,443	7,564
Deferred income taxes		10,285	10,144
		40,820	42,896
SHAREHOLDERS' EQUITY			
Share capital	11	9,863	9,606
Retained earnings		24,390	22,766
Accumulated other comprehensive (loss) income	12	(46)	8
		34,207	32,380
		$ 75,027	$ 75,276

Commitments and contingencies (note 16).

Approved by the Board of Directors on August 4, 2021.

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended **Jun 30 2021**	Three Months Ended Jun 30 2020	Six Months Ended **Jun 30 2021**	Six Months Ended Jun 30 2020
Product sales	17	**$ 7,124**	$ 2,944	**$ 14,143**	$ 7,596
Less: royalties		**(599)**	(73)	**(1,010)**	(225)
Revenue		**6,525**	2,871	**13,133**	7,371
Expenses					
Production		**1,740**	1,409	**3,521**	3,093
Transportation, blending and feedstock		**1,515**	759	**3,023**	2,191
Depletion, depreciation and amortization	4,5	**1,388**	1,403	**2,809**	2,967
Administration		**87**	88	**182**	196
Share-based compensation	9	**137**	23	**266**	(200)
Asset retirement obligation accretion	9	**46**	51	**92**	103
Interest and other financing expense		**177**	199	**362**	405
Risk management activities	15	**28**	32	**57**	(32)
Foreign exchange (gain) loss		**(140)**	(430)	**(302)**	492
Income from North West Redwater Partnership	7	**(400)**	—	**(400)**	—
(Gain) loss from investments	6	**(50)**	(55)	**(169)**	205
		4,528	3,479	**9,441**	9,420
Earnings (loss) before taxes		**1,997**	(608)	**3,692**	(2,049)
Current income tax expense (recovery)	10	**317**	(31)	**614**	(210)
Deferred income tax expense (recovery)	10	**129**	(267)	**150**	(247)
Net earnings (loss)		**$ 1,551**	$ (310)	**$ 2,928**	$ (1,592)
Net earnings (loss) per common share					
Basic	14	**$ 1.31**	$ (0.26)	**$ 2.47**	$ (1.35)
Diluted	14	**$ 1.30**	$ (0.26)	**$ 2.46**	$ (1.35)

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(millions of Canadian dollars, unaudited)	Three Months Ended **Jun 30 2021**	Three Months Ended Jun 30 2020	Six Months Ended **Jun 30 2021**	Six Months Ended Jun 30 2020
Net earnings (loss)	**$ 1,551**	$ (310)	**$ 2,928**	$ (1,592)
Items that may be reclassified subsequently to net earnings (loss)				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income (loss) during the period, net of taxes of $1 million (2020 – $2 million) – three months ended; $2 million (2020 – $3 million) – six months ended	**7**	(13)	**18**	26
Reclassification to net earnings (loss), net of taxes of $nil (2020 – $nil) – three months ended; $1 million (2020 – $1 million) – six months ended	**(1)**	(2)	**(5)**	(9)
	6	(15)	**13**	17
Foreign currency translation adjustment				
Translation of net investment	**(31)**	(107)	**(67)**	147
Other comprehensive (loss) income, net of taxes	**(25)**	(122)	**(54)**	164
Comprehensive income (loss)	**$ 1,526**	$ (432)	**$ 2,874**	$ (1,428)

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Six Months Ended Jun 30 2021	Jun 30 2020
Share capital	11		
Balance – beginning of period		**$ 9,606**	$ 9,533
Issued upon exercise of stock options		**264**	35
Previously recognized liability on stock options exercised for common shares		**39**	9
Purchase of common shares under Normal Course Issuer Bid		**(46)**	(56)
Balance – end of period		**9,863**	9,521
Retained earnings			
Balance – beginning of period		**22,766**	25,424
Net earnings (loss)		**2,928**	(1,592)
Dividends on common shares	11	**(1,114)**	(1,003)
Purchase of common shares under Normal Course Issuer Bid	11	**(190)**	(215)
Balance – end of period		**24,390**	22,614
Accumulated other comprehensive (loss) income	12		
Balance – beginning of period		**8**	34
Other comprehensive (loss) income, net of taxes		**(54)**	164
Balance – end of period		**(46)**	198
Shareholders' equity		**$ 34,207**	$ 32,333

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Jun 30 2021**	Three Months Ended Jun 30 2020	Six Months Ended **Jun 30 2021**	Six Months Ended Jun 30 2020
Operating activities					
Net earnings (loss)		**$ 1,551**	$ (310)	**$ 2,928**	$ (1,592)
Non-cash items					
Depletion, depreciation and amortization		**1,388**	1,403	**2,809**	2,967
Share-based compensation		**137**	23	**266**	(200)
Asset retirement obligation accretion		**46**	51	**92**	103
Unrealized risk management loss (gain)		**10**	1	**30**	(16)
Unrealized foreign exchange (gain) loss		**(151)**	(433)	**(323)**	688
Realized foreign exchange gain on settlement of cross currency swaps		**—**	—	**—**	(166)
(Gain) loss from investments	6	**(47)**	(53)	**(164)**	215
Deferred income tax expense (recovery)		**129**	(267)	**150**	(247)
Other		**72**	13	**(27)**	(105)
Abandonment expenditures		**(58)**	(40)	**(138)**	(129)
Net change in non-cash working capital		**(137)**	(739)	**(147)**	(144)
Cash flows from (used in) operating activities		**2,940**	(351)	**5,476**	1,374
Financing activities					
(Repayment) issue of bank credit facilities and commercial paper, net	8	**(1,588)**	184	**(2,988)**	833
Repayment of medium-term notes	8	**—**	(900)	**—**	(900)
Issue of US dollar debt securities	8	**—**	1,481	**—**	1,481
Proceeds on settlement of cross currency swaps	15	**—**	—	**—**	166
Payment of lease liabilities	5,9	**(52)**	(61)	**(105)**	(126)
Issue of common shares on exercise of stock options		**191**	4	**264**	35
Dividends on common shares		**(557)**	(502)	**(1,060)**	(946)
Purchase of common shares under Normal Course Issuer Bid	11	**(213)**	—	**(236)**	(271)
Cash flows (used in) from financing activities		**(2,219)**	206	**(4,125)**	272
Investing activities					
Net proceeds (expenditures) on exploration and evaluation assets	3,17	**3**	(1)	**(1)**	(8)
Net expenditures on property, plant and equipment	4,17	**(1,244)**	(380)	**(1,981)**	(1,122)
Repayment of North West Redwater Partnership subordinated debt advances	7	**555**	—	**555**	—
Net change in non-cash working capital		**(33)**	(312)	**60**	(422)
Cash flows used in investing activities		**(719)**	(693)	**(1,367)**	(1,552)
Increase (decrease) in cash and cash equivalents		**2**	(838)	**(16)**	94
Cash and cash equivalents – beginning of period		**166**	1,071	**184**	139
Cash and cash equivalents – end of period		**$ 168**	$ 233	**$ 168**	$ 233
Interest paid on long-term debt, net		**$ 142**	$ 174	**$ 354**	$ 387
Income taxes paid (received)		**$ 38**	$ 31	**$ (83)**	$ 72

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 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, 2020, 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 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, 2020.

Critical Accounting Estimates and Judgements

For the three and six months ended June 30, 2021, the novel coronavirus ("COVID-19") continued to have an impact on the global economy, including the oil and gas industry. Business conditions in the second quarter of 2021 continued to reflect the market uncertainty associated with COVID-19, with some improvements to global crude oil demand and supply conditions. 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.

2. CHANGES IN ACCOUNTING POLICIES

In August 2020, the IASB issued Interest Rate Benchmark Reform (Phase 2) in response to the Financial Stability Board's mandated reforms to InterBank Offered Rates ("IBORs"), with financial regulators proposing that current IBOR benchmark rates be replaced by a number of new local currency denominated alternative benchmark rates. The Company retrospectively adopted the amendments on January 1, 2021. Adoption of these amendments did not have a significant impact on the Company's financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2020	$ 2,101	$ —	$ 83	$ 252	$ 2,436
Additions	**2**	**—**	**3**	**—**	**5**
Transfers to property, plant and equipment	**(35)**	**—**	**—**	**—**	**(35)**
At June 30, 2021	**$ 2,068**	**$ —**	**$ 86**	**$ 252**	**$ 2,406**

4. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2020	$ 73,997	$ 7,283	$ 3,963	$ 45,710	$ 457	$ 485	$ 131,895
Additions	**801**	**70**	**30**	**1,064**	**3**	**9**	**1,977**
Transfers from E&E assets	**35**	**—**	**—**	**—**	**—**	**—**	**35**
Derecognitions and other [1]	**(190)**	**—**	**—**	**(300)**	**—**	**—**	**(490)**
Foreign exchange adjustments and other	**—**	**(201)**	**(110)**	**—**	**—**	**—**	**(311)**
At June 30, 2021	**$ 74,643**	**$ 7,152**	**$ 3,883**	**$ 46,474**	**$ 460**	**$ 494**	**$ 133,106**
Accumulated depletion and depreciation							
At December 31, 2020	$ 49,641	$ 5,853	$ 2,822	$ 7,289	$ 168	$ 370	$ 66,143
Expense	**1,698**	**81**	**63**	**836**	**7**	**12**	**2,697**
Derecognitions and other [1]	**(190)**	**—**	**—**	**(300)**	**—**	**—**	**(490)**
Foreign exchange adjustments and other	**14**	**(167)**	**(79)**	**(5)**	**—**	**—**	**(237)**
At June 30, 2021	**$ 51,163**	**$ 5,767**	**$ 2,806**	**$ 7,820**	**$ 175**	**$ 382**	**$ 68,113**
Net book value							
- at June 30, 2021	**$ 23,480**	**$ 1,385**	**$ 1,077**	**$ 38,654**	**$ 285**	**$ 112**	**$ 64,993**
- at December 31, 2020	$ 24,356	$ 1,430	$ 1,141	$ 38,421	$ 289	$ 115	$ 65,752

(1) An asset is derecognized when no future economic benefits are expected to arise from its continued use or disposal.

5. LEASES

Lease assets

		Product transportation and storage		Field equipment and power		Offshore vessels and equipment		Office leases and other		Total
At December 31, 2020	$	1,038	$	379	$	128	$	100	$	1,645
Additions		**16**		**17**		**—**		**2**		**35**
Depreciation		**(58)**		**(28)**		**(14)**		**(12)**		**(112)**
Foreign exchange adjustments and other		**—**		**—**		**(3)**		**—**		**(3)**
At June 30, 2021	**$**	**996**	**$**	**368**	**$**	**111**	**$**	**90**	**$**	**1,565**

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, 2021 were as follows:

		Jun 30 2021		Dec 31 2020
Lease liabilities	**$**	**1,619**	$	1,690
Less: current portion		**186**		189
	$	**1,433**	$	1,501

Total cash outflows for leases for the three months ended June 30, 2021, including payments related to short-term leases not reported as lease assets, were $286 million (three months ended June 30, 2020 – $230 million; six months ended June 30, 2021 – $574 million; six months ended June 30, 2020 – $549 million). Interest expense on leases for the three months ended June 30, 2021 was $16 million (three months ended June 30, 2020 – $17 million; six months ended June 30, 2021 – $32 million; six months ended June 30, 2020 – $34 million).

6. INVESTMENTS

As at June 30, 2021, the Company had the following investments:

		Jun 30 2021		Dec 31 2020
Investment in PrairieSky Royalty Ltd.	**$**	**340**	$	228
Investment in Inter Pipeline Ltd.		**129**		77
	$	**469**	$	305

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

	Three Months Ended				Six Months Ended			
		Jun 30 2021		Jun 30 2020		**Jun 30 2021**		Jun 30 2020
Fair value (gain) loss from investments	**$**	**(47)**	$	(53)	**$**	**(164)**	$	215
Dividend income from investments		**(3)**		(2)		**(5)**		(10)
	$	**(50)**	$	(55)	**$**	**(169)**	$	205

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, 2021, the Company's investments in PrairieSky and Inter Pipeline were classified as current assets.

The Company's investment in PrairieSky consists of approximately 22.6 million common shares. As at June 30, 2021, the market price per common share was $15.01 (December 31, 2020 – $10.09; June 30, 2020 – $8.58).

The Company's investment in Inter Pipeline consists of approximately 6.4 million common shares. As at June 30, 2021, the market price per common share was $20.15 (December 31, 2020 – $11.87; June 30, 2020 – $12.64).

7. OTHER LONG-TERM ASSETS

	Jun 30 2021	Dec 31 2020
North West Redwater Partnership ("NWRP")	$ —	$ 555
Prepaid cost of service tolls	159	162
Risk management (note 15)	203	136
Long-term inventory	128	121
Other (1)	213	190
	703	1,164
Less: current portion	124	82
	$ 579	$ 1,082

(1) Includes physical product sales contracts valued at $99 million at June 30, 2021 (December 31, 2020 - $111 million).

The Company has a 50% equity investment in NWRP. NWRP operates a 50,000 barrels per day bitumen upgrader and refinery that processes approximately 12,500 barrels per day (25% toll payer) of bitumen feedstock for the Company and 37,500 barrels per day (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

On June 30, 2021, the equity partners together with the toll payers, agreed to optimize the structure of NWRP to better align the commercial interests of the equity partners and the toll payers (the "Optimization Transaction"). As a result, North West Refining Inc. transferred its entire 50% partnership interest in NWRP to APMC. The Company's 50% equity interest remained unchanged.

Under the Optimization Transaction, the original term of the processing agreements was extended by 10 years from 2048 to 2058. NWRP retired higher cost subordinated debt, which carried interest rates of prime plus 6%, with lower cost senior secured bonds at an average rate of approximately 2.55%, reducing interest costs to NWRP and associated tolls to the toll payers. As such, NWRP repaid the Company's and APMC's subordinated debt advances of $555 million each. In addition, the Company received a $400 million distribution from NWRP.

To facilitate the Optimization Transaction, NWRP issued $500 million of 1.20% series L senior secured bonds due December 2023, $500 million of 2.00% series M senior secured bonds due December 2026, $1,000 million of 2.80% series N senior secured bonds due June 2031, and $600 million of 3.75% series O senior secured bonds due June 2051. Additionally, NWRP's existing $3,500 million syndicated credit facility was amended. The $2,000 million revolving credit facility was extended by three years to June 2024, and the $1,500 million non-revolving credit facility was reduced by $500 million to $1,000 million and extended by two years to June 2023.

As at June 30, 2021, the cumulative unrecognized share of the equity loss from NWRP of $129 million and total partnership distributions in excess of the cumulative share of equity income, was $529 million (December 31, 2020 – $153 million; June 30, 2020 – $175 million). For the three months ended June 30, 2021, unrecognized equity income was $7 million, (six months ended June 30, 2021 – unrecognized equity income of $24 million; three months ended June 30, 2020 – unrecognized equity loss of $23 million; six months ended June 30, 2020 – unrecognized equity loss of $116 million).

8. LONG-TERM DEBT

	Jun 30 2021	Dec 31 2020
Canadian dollar denominated debt, unsecured		
Bank credit facilities	$ —	$ 1,614
Medium-term notes	3,200	3,200
	3,200	4,814
US dollar denominated debt, unsecured		
Bank credit facilities (June 30, 2021 – US$2,973 million; December 31, 2020 – US$3,953 million)	3,688	5,041
Commercial paper (June 30, 2021 – US$550 million; December 31,2020 – US$426 million)	682	544
US dollar debt securities (June 30, 2021 – US$8,750 million; December 31, 2020 – US$8,750 million)	10,854	11,161
	15,224	16,746
Long-term debt before transaction costs and original issue discounts, net	18,424	21,560
Less: original issue discounts, net (1)	17	18
transaction costs (1) (2)	76	89
	18,331	21,453
Less: current portion of commercial paper	682	544
current portion of other long-term debt (1) (2)	1,618	799
	$ 16,031	$ 20,110

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

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

Bank Credit Facilities and Commercial Paper

As at June 30, 2021, the Company had undrawn revolving bank credit facilities of $4,959 million. Additionally, the Company had in place fully drawn term credit facilities of $3,650 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. At June 30, 2021, the Company had $682 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

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

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

During the first quarter of 2021, the $1,000 million non-revolving term credit facility, originally due February 2022, was extended to February 2023.

During 2019, the Company entered into a $3,250 million non-revolving term credit facility with an original maturity of June 2022, to finance the acquisition of assets from Devon Canada Corporation. During the second quarter of 2021, the outstanding balance of $2,125 million was repaid and the facility was cancelled.

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 of 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, 2021 was 1.0% (June 30, 2020 – 1.4%), and on total long-term debt outstanding for the six months ended June 30, 2021 was 3.4% (June 30, 2020 – 3.7%).

As at June 30, 2021, letters of credit and guarantees aggregating to $492 million were outstanding.

Medium-Term Notes

As at June 30, 2021, the Company had $2,200 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of up to $3,000 million of medium-term notes in Canada. Subsequent to June 30, 2021, 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 2023, replacing the Company's previous base shelf prospectus, which would have expired 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

As at June 30, 2021, the Company had US$1,900 million remaining on its base shelf prospectus that allowed for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States. Subsequent to June 30, 2021, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$3,000 million of debt securities in the United States, which expires in August 2023, replacing the Company's previous base shelf prospectus, which would have expired 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.

Subsequent to June 30, 2021, the Company filed a notice for the early repayment of US$500 million of 3.45% debt securities in August 2021, originally due November 2021.

9. OTHER LONG-TERM LIABILITIES

	Jun 30 2021	Dec 31 2020
Asset retirement obligations	**$ 5,787**	$ 5,861
Lease liabilities (note 5)	**1,619**	1,690
Share-based compensation	**350**	160
Risk management (note 15)	**64**	160
Transportation and processing contracts	**226**	270
Other [1]	**115**	145
	8,161	8,286
Less: current portion	**718**	722
	$ 7,443	$ 7,564

(1) Includes $47 million related to the acquisition of the Joslyn oil sands project in 2018, payable in annual installments of $25 million over the next two years.

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 3.7% (December 31, 2020 – 3.7%) and inflation rates of up to 2% (December 31, 2020 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Jun 30 2021	Dec 31 2020
Balance – beginning of period	**$ 5,861**	$ 5,771
Liabilities incurred	**4**	5
Liabilities acquired, net	**—**	13
Liabilities settled	**(138)**	(249)
Asset retirement obligation accretion	**92**	205
Revision of cost and timing estimates	**(6)**	(134)
Change in discount rates	**—**	253
Foreign exchange adjustments	**(26)**	(3)
Balance – end of period	**5,787**	5,861
Less: current portion	**132**	184
	$ 5,655	$ 5,677

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 2021	Dec 31 2020
Balance – beginning of period	**$ 160**	$ 297
Share-based compensation expense (recovery)	**266**	(82)
Cash payment for stock options surrendered and PSUs vested	**(39)**	(39)
Transferred to common shares	**(39)**	(21)
Other	**2**	5
Balance – end of period	**350**	160
Less: current portion	**268**	119
	$ 82	$ 41

Included within share-based compensation liability as at June 30, 2021 was $47 million related to PSUs granted to certain executive employees (December 31, 2020 – $49 million).

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended		Six Months Ended	
Expense (recovery)	**Jun 30 2021**	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Current corporate income tax – North America	**$ 324**	$ (34)	**$ 609**	$ (228)
Current corporate income tax – North Sea	**(5)**	1	**6**	10
Current corporate income tax – Offshore Africa	**7**	2	**11**	6
Current PRT [(1)] – North Sea	**(12)**	—	**(17)**	—
Other taxes	**3**	—	**5**	2
Current income tax	**317**	(31)	**614**	(210)
Deferred income tax	**129**	(267)	**150**	(247)
Income tax	**$ 446**	$ (298)	**$ 764**	$ (457)

(1) Petroleum Revenue Tax

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Six Months Ended Jun 30, 2021	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,183,866**	**$ 9,606**
Issued upon exercise of stock options	**7,369**	**264**
Previously recognized liability on stock options exercised for common shares	**—**	**39**
Purchase of common shares under Normal Course Issuer Bid	**(5,640)**	**(46)**
Balance – end of period	**1,185,595**	**$ 9,863**

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 3, 2021, the Board of Directors declared a quarterly dividend of $0.47 per common share, an increase from the previous quarterly dividend of $0.425 per common share.

Normal Course Issuer Bid

On March 9, 2021, 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 59,278,474 common shares, over a 12-month period commencing March 11, 2021 and ending March 10, 2022.

For the six months ended June 30, 2021, the Company purchased 5,640,000 common shares at a weighted average price of $41.89 per common share for a total cost of $236 million. Retained earnings were reduced by $190 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to June 30, 2021, the Company purchased 5,404,400 common shares at a weighted average price of $42.12 per common share for a total cost of $228 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at June 30, 2021:

	Six Months Ended Jun 30, 2021		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**48,656**	**$**	**37.53**
Granted	**11,390**	**$**	**32.93**
Exercised for common shares	**(7,369)**	**$**	**35.89**
Surrendered for cash settlement	**(451)**	**$**	**37.25**
Forfeited	**(2,070)**	**$**	**35.79**
Outstanding – end of period	**50,156**	**$**	**36.80**
Exercisable – end of period	**14,333**	**$**	**40.79**

The Stock 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.

12. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

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

		Jun 30 2021		Jun 30 2020
Derivative financial instruments designated as cash flow hedges	**$**	**82**	$	88
Foreign currency translation adjustment		**(128)**		110
	$	**(46)**	$	198

13. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and to support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the arithmetic ratio of net current and long-term debt divided by the sum of the carrying value of shareholders' equity plus net current and long-term debt. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. This range may be exceeded in periods when a combination of capital projects, acquisitions, or lower commodity prices occurs. The Company may be below the low end of the targeted range when cash flow from operating activities is greater than current investment activities. At June 30, 2021, the ratio was within the target range at 34.7%.

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 2021		Dec 31 2020
Long-term debt, net [(1)]	**$**	**18,163**	$	21,269
Total shareholders' equity	**$**	**34,207**	$	32,380
Debt to book capitalization		**34.7%**		39.6%

(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, 2021, the Company was in compliance with this covenant.

14. NET EARNINGS (LOSS) PER COMMON SHARE

	Three Months Ended		Six Months Ended	
	Jun 30 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Weighted average common shares outstanding – basic (thousands of shares)	**1,185,301**	1,180,925	**1,185,425**	1,182,031
Effect of dilutive stock options (thousands of shares)	**5,163**	—	**3,038**	—
Weighted average common shares outstanding – diluted (thousands of shares)	**1,190,464**	1,180,925	**1,188,463**	1,182,031
Net earnings (loss)	**$ 1,551**	$ (310)	**$ 2,928**	$ (1,592)
Net earnings (loss) per common share – basic	**$ 1.31**	$ (0.26)	**$ 2.47**	$ (1.35)
– diluted	**$ 1.30**	$ (0.26)	**$ 2.46**	$ (1.35)

15. FINANCIAL INSTRUMENTS

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

	Jun 30, 2021				
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	**$ 3,184**	**$ —**	**$ —**	**$ —**	**$ 3,184**
Investments	**—**	**469**	**—**	**—**	**469**
Other long-term assets	**—**	**3**	**200**	**—**	**203**
Accounts payable	**—**	**—**	**—**	**(783)**	**(783)**
Accrued liabilities	**—**	**—**	**—**	**(2,889)**	**(2,889)**
Other long-term liabilities (1)	**—**	**(64)**	**—**	**(1,666)**	**(1,730)**
Long-term debt (2)	**—**	**—**	**—**	**(18,331)**	**(18,331)**
	$ 3,184	**$ 408**	**$ 200**	**$ (23,669)**	**$ (19,877)**

	Dec 31, 2020				
Asset (liability)	Financial assets at amortized cost	Fair value through profit or loss	Derivatives used for hedging	Financial liabilities at amortized cost	Total
Accounts receivable	$ 2,190	$ —	$ —	$ —	$ 2,190
Investments	—	305	—	—	305
Other long-term assets	555	—	136	—	691
Accounts payable	—	—	—	(667)	(667)
Accrued liabilities	—	—	—	(2,346)	(2,346)
Other long-term liabilities (1)	—	(52)	(108)	(1,762)	(1,922)
Long-term debt (2)	—	—	—	(21,453)	(21,453)
	$ 2,745	$ 253	$ 28	$ (26,228)	$ (23,202)

(1) Includes $1,619 million of lease liabilities (December 31, 2020 – $1,690 million) and $47 million of deferred purchase consideration payable over the next two years (December 31, 2020 – $72 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, 2021							
	Carrying amount		**Fair value**					
Asset (liability) (1) (2)			**Level 1**		**Level 2**		**Level 3** (4)	
Investments (3)	**$**	**469**	**$**	**469**	**$**	**—**	**$**	**—**
Other long-term assets	**$**	**203**	**$**	**—**	**$**	**203**	**$**	**—**
Other long-term liabilities	**$**	**(111)**	**$**	**—**	**$**	**(64)**	**$**	**(47)**
Fixed rate long-term debt (6) (7)	**$**	**(13,961)**	**$**	**(16,093)**	**$**	**—**	**$**	**—**

	Dec 31, 2020							
	Carrying amount		Fair value					
Asset (liability) (1) (2)			Level 1		Level 2		Level 3 (4) (5)	
Investments (3)	$	305	$	305	$	—	$	—
Other long-term assets	$	691	$	—	$	136	$	555
Other long-term liabilities	$	(232)	$	—	$	(160)	$	(72)
Fixed rate long-term debt (6) (7)	$	(14,254)	$	(16,598)	$	—	$	—

(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 was 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 2021**		Dec 31 2020
Derivatives held for trading				
Natural gas fixed price swaps	**$**	**(26)**	$	(5)
Natural gas basis swaps		**(38)**		(40)
Foreign currency forward contracts		**3**		(7)
Cash flow hedges				
Foreign currency forward contracts		**67**		(108)
Cross currency swaps		**133**		136
	$	**139**	$	(24)
Included within:				
Current portion of other long-term assets	**$**	**75**	$	5
Current portion of other long-term liabilities		**(39)**		(131)
Other long-term assets		**128**		131
Other long-term liabilities		**(25)**		(29)
	$	**139**	$	(24)

For the six months ended June 30, 2021, the ineffectiveness arising from cash flow hedges was $nil (year ended December 31, 2020 – loss of $1 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 2021**	Dec 31 2020
Balance – beginning of period	**$ (24)**	$ 178
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities	**(9)**	(32)
Foreign exchange	**158**	(168)
Other comprehensive income (loss)	**14**	(2)
Balance – end of period	**139**	(24)
Less: current portion	**36**	(126)
	$ 103	$ 102

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

	Three Months Ended		Six Months Ended	
	Jun 30 2021	Jun 30 2020	**Jun 30 2021**	Jun 30 2020
Net realized risk management loss (gain)	**$ 18**	$ 31	**$ 27**	$ (16)
Net unrealized risk management loss (gain)	**10**	1	**30**	(16)
	$ 28	$ 32	**$ 57**	$ (32)

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, 2021, the Company had the following derivative financial instruments outstanding:

	Remaining term		Weighted average volume	Weighted average price	Index
Natural Gas					
Fixed price swap	Jul 2021 –	Dec 2021	32,584 GJ/d	$2.00/GJ	AECO
	Jul 2021 –	Dec 2021	20,027 MMBtu/d	US$2.40/MMBtu	DAWN
	Jul 2021 –	Dec 2021	16,685 MMBtu/d	US$2.52/MMBtu	NYMEX
	Jul 2021 –	Dec 2021	15,000 MMBtu/d	US$2.62/MMBtu	SUMAS
Differential swap	Jul 2021 –	Aug 2021	20,000 GJ/d	$0.29/GJ	AECO-STN 2
Basis swap	Jul 2021 –	Dec 2023	54,978 MMBtu/d	US$1.23/MMBtu	AECO
	Jan 2024 –	Dec 2025	20,000 MMBtu/d	US$0.97/MMBtu	AECO
	Jul 2021 –	Dec 2021	20,000 MMBtu/d	US$0.09/MMBtu	DAWN

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, 2021, 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, 2021, 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 2021	–	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, 2021 and was classified as a cash flow hedge.

In addition to the cross currency swap contract noted above, at June 30, 2021, the Company had US$4,056 million of foreign currency forward contracts outstanding, with original terms of up to 90 days, including US$3,523 million designated as cash flow hedges.

b) Credit risk

Credit risk is the risk that a party to a financial instrument will cause a financial loss to the Company by failing to discharge an obligation.

Counterparty credit risk management

The Company’s accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At June 30, 2021, 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, 2021, the Company had net risk management assets of $170 million with specific counterparties related to derivative financial instruments (December 31, 2020 – $129 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	$ 783	$ —	$ —	$ —
Accrued liabilities	$ 2,889	$ —	$ —	$ —
Long-term debt (1)	$ 2,300	$ 4,931	$ 3,109	$ 8,084
Other long-term liabilities (2)	$ 250	$ 189	$ 414	$ 877
Interest and other financing expense (3)	$ 694	$ 629	$ 1,505	$ 4,123

(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, $186 million; one to less than two years, $153 million; two to less than five years, $403 million; and thereafter, $877 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, 2021.

16. 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, 2021:

	Remaining 2021	2022	2023	2024	2025	Thereafter
Product transportation and processing (1)	$ 442	$ 838	$ 907	$ 846	$ 811	$ 10,360
North West Redwater Partnership service toll (2)	$ 63	$ 123	$ 123	$ 122	$ 119	$ 3,784
Offshore vessels and equipment	$ 33	$ 41	$ —	$ —	$ —	$ —
Field equipment and power	$ 14	$ 21	$ 21	$ 21	$ 21	$ 246
Other	$ 14	$ 21	$ 20	$ 21	$ 21	$ 16

(1) Includes commitments pertaining to a 20-year product transportation agreement on the Trans Mountain Pipeline Expansion.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,546 million of interest payable over the 40-year tolling period (note 7).

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

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

17. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	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	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs	**3,446**	974	**6,541**	2,824	**69**	99	**269**	232	**140**	22	**218**	106	**3,655**	1,095	**7,028**	3,162
Natural gas	**453**	256	**939**	531	**1**	2	**2**	10	**10**	12	**15**	20	**464**	270	**956**	561
Other income and revenue (1)	**22**	21	**53**	11	**—**	2	**—**	3	**1**	1	**3**	3	**23**	24	**56**	17
Total segmented product sales	**3,921**	1,251	**7,533**	3,366	**70**	103	**271**	245	**151**	35	**236**	129	**4,142**	1,389	**8,040**	3,740
Less: royalties	**(395)**	(65)	**(680)**	(179)	**(1)**	(1)	**(1)**	(1)	**(6)**	(1)	**(10)**	(5)	**(402)**	(67)	**(691)**	(185)
Segmented revenue	**3,526**	1,186	**6,853**	3,187	**69**	102	**270**	244	**145**	34	**226**	124	**3,740**	1,322	**7,349**	3,555
Segmented expenses																
Production	**714**	585	**1,441**	1,294	**54**	67	**168**	161	**26**	13	**47**	35	**794**	665	**1,656**	1,490
Transportation, blending and feedstock	**1,144**	546	**2,290**	1,616	**2**	4	**4**	11	**—**	—	**—**	—	**1,146**	550	**2,294**	1,627
Depletion, depreciation and amortization	**881**	871	**1,749**	1,826	**19**	76	**87**	175	**44**	27	**75**	68	**944**	974	**1,911**	2,069
Asset retirement obligation accretion	**25**	23	**50**	50	**5**	8	**10**	15	**2**	2	**3**	3	**32**	33	**63**	68
Risk management activities (commodity derivatives)	**17**	4	**36**	6	**—**	—	**—**	—	**—**	—	**—**	—	**17**	4	**36**	6
Income from North West Redwater Partnership	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—
Total segmented expenses	**2,781**	2,029	**5,566**	4,792	**80**	155	**269**	362	**72**	42	**125**	106	**2,933**	2,226	**5,960**	5,260
Segmented earnings (loss) before the following	**745**	(843)	**1,287**	(1,605)	**(11)**	(53)	**1**	(118)	**73**	(8)	**101**	18	**807**	(904)	**1,389**	(1,705)
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 expense (recovery)																
Deferred income tax expense (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	
	2021	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Segmented product sales																
Crude oil and NGLs [(2)]	**2,794**	1,343	**5,777**	3,547	**21**	20	**40**	41	**(88)**	4	**(175)**	35	**6,382**	2,462	**12,670**	6,785
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**45**	37	**108**	83	**509**	307	**1,064**	644
Other income and revenue [(1)]	**30**	103	**40**	100	**171**	25	**302**	25	**9**	23	**11**	25	**233**	175	**409**	167
Total segmented product sales	**2,824**	1,446	**5,817**	3,647	**192**	45	**342**	66	**(34)**	64	**(56)**	143	**7,124**	2,944	**14,143**	7,596
Less: royalties	**(197)**	(6)	**(319)**	(40)	**—**	—	**—**	—	**—**	—	**—**	—	**(599)**	(73)	**(1,010)**	(225)
Segmented revenue	**2,627**	1,440	**5,498**	3,607	**192**	45	**342**	66	**(34)**	64	**(56)**	143	**6,525**	2,871	**13,133**	7,371
Segmented expenses																
Production	**850**	730	**1,688**	1,539	**79**	29	**142**	35	**17**	(15)	**35**	29	**1,740**	1,409	**3,521**	3,093
Transportation, blending and feedstock [(2)]	**294**	183	**591**	453	**134**	22	**239**	22	**(59)**	4	**(101)**	89	**1,515**	759	**3,023**	2,191
Depletion, depreciation and amortization	**441**	451	**891**	891	**3**	3	**7**	7	**—**	(25)	**—**	—	**1,388**	1,403	**2,809**	2,967
Asset retirement obligation accretion	**14**	18	**29**	35	**—**	—	**—**	—	**—**	—	**—**	—	**46**	51	**92**	103
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**17**	4	**36**	6
Income from North West Redwater Partnership	**—**	—	**—**	—	**(400)**	—	**(400)**	—	**—**	—	**—**	—	**(400)**	—	**(400)**	—
Total segmented expenses	**1,599**	1,382	**3,199**	2,918	**(184)**	54	**(12)**	64	**(42)**	(36)	**(66)**	118	**4,306**	3,626	**9,081**	8,360
Segmented earnings (loss) before the following	**1,028**	58	**2,299**	689	**376**	(9)	**354**	2	**8**	100	**10**	25	**2,219**	(755)	**4,052**	(989)
Non–segmented expenses																
Administration													**87**	88	**182**	196
Share-based compensation													**137**	23	**266**	(200)
Interest and other financing expense													**177**	199	**362**	405
Risk management activities (other)													**11**	28	**21**	(38)
Foreign exchange (gain) loss													**(140)**	(430)	**(302)**	492
(Gain) loss from investments													**(50)**	(55)	**(169)**	205
Total non-segmented expenses													**222**	(147)	**360**	1,060
Earnings (loss) before taxes													**1,997**	(608)	**3,692**	(2,049)
Current income tax expense (recovery)													**317**	(31)	**614**	(210)
Deferred income tax expense (recovery)													**129**	(267)	**150**	(247)
Net earnings (loss)													**1,551**	(310)	**2,928**	(1,592)

(1) Includes the sale of diesel and other refined products and other income, including government grants and recoveries associated with the joint operations 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, 2021			Jun 30, 2020		
	Net expenditures (proceeds)	**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	**$ (2)**	**$ (31)**	**$ (33)**	$ 7	$ (64)	$ (57)
Offshore Africa	**3**	**—**	**3**	1	—	1
	$ 1	**$ (31)**	**$ (30)**	$ 8	$ (64)	$ (56)
Property, plant and equipment						
Exploration and Production						
North America	**$ 799**	**$ (153)**	**$ 646**	$ 483	$ (988)	$ (505)
North Sea	**76**	**(6)**	**70**	43	(114)	(71)
Offshore Africa	**30**	**—**	**30**	41	(29)	12
	905	**(159)**	**746**	567	(1,131)	(564)
Oil Sands Mining and Upgrading [3]	**1,064**	**(300)**	**764**	539	(482)	57
Midstream and Refining	**3**	**—**	**3**	3	(1)	2
Head office	**9**	**—**	**9**	13	—	13
	$ 1,981	**$ (459)**	**$ 1,522**	$ 1,122	$ (1,614)	$ (492)

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

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

(3) *Net expenditures includes the acquisition of a 5% net carried interest on an existing oil sands lease in the second quarter of 2021, capitalized interest and share-based compensation.*

Segmented Assets

	Jun 30 2021	Dec 31 2020
Exploration and Production		
North America	**$ 28,607**	$ 29,094
North Sea	**1,476**	1,624
Offshore Africa	**1,415**	1,407
Other	**82**	81
Oil Sands Mining and Upgrading	**42,343**	41,567
Midstream and Refining	**912**	1,301
Head office	**192**	202
	$ 75,027	$ 75,276

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, 2021:	
Interest coverage (times)	
Net earnings (1)	7.7x
Adjusted funds flow (2)	14.5x

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

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

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CORPORATE INFORMATION

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Aberdeen, Scotland

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

Barry Duncan
Vice-President, Finance, International

Stock Listing

Toronto Stock Exchange
Trading Symbol - CNQ

New York Stock Exchange
Trading Symbol - CNQ

Registrar and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta

Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Investor Relations

Telephone: (403) 514-7777
Email: ir@cnrl.com

CANADIAN NATURAL RESOURCES LIMITED
2100, 855 - 2nd Street S.W., Calgary, Alberta T2P 4J8
Telephone: (403) 517-6700 Facsimile: (403) 517-7350
Website: www.cnrl.com
Printed in Canada