Canadian Natural

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2023 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2023 FIRST QUARTER RESULTS

Commenting on the Company's first quarter 2023 results, Tim McKay, President, stated "Canadian Natural delivered strong results in Q1/23 with effective and efficient operations on our balanced and diverse portfolio of high quality assets. Our culture of continuous improvement, focus on cost control and disciplined capital allocation continues to drive strong financial results and maximize value for our shareholders. In Q1/23, we delivered total quarterly production of approximately 1,319 MBOE/d, including record natural gas production of 2,139 MMcf/d and liquids production of 962,908 bbl/d. We generated strong quarterly free cash flow of approximately $1.4 billion, after dividends of approximately $0.9 billion and net base capital expenditures of approximately $1.1 billion. In addition, our strategic growth capital expenditures of approximately $0.28 billion in the quarter was targeted to provide mid-term growth across our asset base as we unlock value from our projects with strong capital efficiencies. With ample liquidity on our balance sheet, we can add production with minimal capital while generating significant returns on capital and maximizing shareholder value.

Canadian Natural is a leader on Environmental, Social and Governance ("ESG") and has made it a priority to work collaboratively with industry peers and governments to achieve meaningful greenhouse gas ("GHG") emissions reductions in support of Alberta and Canada's climate goals. The Alberta government’s recently announced Emissions Reduction and Energy Development Plan ("ERED") builds upon the province’s longstanding climate leadership and achievements in emissions reductions. Canadian Natural looks forward to supporting the Province of Alberta in continuing to provide affordable, reliable, responsibly produced energy while reducing emissions and aspiring towards a net zero economy by 2050. Canadian Natural's current environmental goals support Alberta's climate plan where large scale carbon capture and storage ("CCS") projects, like the Pathways Alliance's foundational CCS project, will have a significant role in reducing GHG emissions."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "At Canadian Natural, our culture of continuous improvement and strong employee ownership enables our teams to create significant value for our shareholders across all aspects of the Company. Our effective and flexible capital allocation to our four pillars: returns to shareholders, balance sheet strength, resource value growth, and opportunistic acquisitions continue to deliver robust financial results.

In Q1/23, we generated approximately $1.9 billion in adjusted net earnings and approximately $3.4 billion in adjusted funds flow, resulting in significant free cash flow of approximately $1.4 billion after dividends and base capital expenditures. Year-to-date, we have returned approximately $2.8 billion to shareholders through dividends and share repurchases, up to and including May 3, 2023. Our commitment to increasing shareholder returns is evident in our sustainable and growing quarterly dividend, which was recently increased to $0.90 per share in March 2023, up from $0.85 per share, marking 2023 as the 23rd consecutive year of dividend increases. The increasing dividend and the Company's commitment to return 100% of free cash flow to shareholders, when net debt reaches $10 billion, demonstrates the confidence the Board of Directors has in the Company’s world class assets and its ability to generate significant and sustainable free cash flow throughout the commodity price cycle.

When you combine our leading financial results with our top tier reserves and asset base, this provides us with unique competitive advantages in terms of capital efficiency, flexibility and sustainability, all of which drive material free cash flow generation and strong returns on capital."

QUARTERLY HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Net earnings	**$ 1,799**	$ 1,520	$ 3,101
Per common share – basic	**$ 1.63**	$ 1.37	$ 2.66
– diluted	**$ 1.62**	$ 1.36	$ 2.63
Adjusted net earnings from operations (1)	**$ 1,881**	$ 2,194	$ 3,376
Per common share – basic (2)	**$ 1.71**	$ 1.98	$ 2.90
– diluted (2)	**$ 1.69**	$ 1.96	$ 2.86
Cash flows from operating activities	**$ 1,295**	$ 4,544	$ 2,853
Adjusted funds flow (1)	**$ 3,429**	$ 4,176	$ 4,975
Per common share – basic (2)	**$ 3.12**	$ 3.78	$ 4.27
– diluted (2)	**$ 3.08**	$ 3.73	$ 4.21
Cash flows used in investing activities	**$ 1,153**	$ 1,262	$ 1,251
Net capital expenditures (1), excluding net acquisition costs and strategic growth capital (3)	**$ 1,117**	$ 850	$ 844
Net capital expenditures (1)	**$ 1,394**	$ 1,317	$ 1,455
Daily production, before royalties			
Natural gas (MMcf/d)	**2,139**	2,115	2,006
Crude oil and NGLs (bbl/d)	**962,908**	942,258	945,809
Equivalent production (BOE/d) (4)	**1,319,391**	1,294,679	1,280,180

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023.

(3) Net capital expenditures, excluding net acquisition costs and strategic growth capital, is defined as base capital expenditures.

(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.

- The strength of Canadian Natural's long life low decline asset base, supported by safe, effective and efficient operations, makes our business unique, robust and sustainable. In Q1/23, the Company generated strong financial results, including:
  - Net earnings of approximately $1.8 billion and adjusted net earnings from operations of approximately $1.9 billion.
  - Cash flows from operating activities of approximately $1.3 billion.
  - Adjusted funds flow of approximately $3.4 billion.
  - Free cash flow(1) of approximately $1.4 billion(2) after total dividend payments of approximately $0.9 billion and base capital expenditures(3) of approximately $1.1 billion.
- Returns to shareholders in Q1/23 were strong, totaling approximately $1.6 billion, comprised of approximately $0.9 billion of dividends and approximately $0.7 billion of share repurchases.
  - Canadian Natural increased its sustainable and growing quarterly dividend in March 2023 to $0.90 per common share, up 6% from $0.85 per common share, marking 2023 as the 23rd consecutive year of dividend increases and demonstrating the confidence that the Board of Directors has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base.

  - In Q1/23, the Company repurchased approximately 8.9 million common shares for cancellation at a weighted average price of $76.96 per share for a total of approximately $0.7 billion.
  - In March 2023, the Company renewed its Normal Course Issuer Bid ("NCIB") which states that during the 12 month period commencing March 13, 2023 and ending March 12, 2024, the Company can repurchase for cancellation up to 10% of the public float (determined in accordance with the rules of the TSX), up to a maximum of approximately 92.3 million common shares.
- Year-to-date, up to and including May 3, 2023, the Company has returned approximately $2.8 billion to shareholders through approximately $1.9 billion in dividends and $0.9 billion through the repurchase and cancellation of approximately 11.1 million common shares.
- Subsequent to quarter end, the Company declared a quarterly dividend of $0.90 per share, payable on July 5, 2023 to shareholders of record on June 16, 2023.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately $11.9 billion in net debt[(1)] and significant liquidity[(1)] of approximately $6.1 billion at the end of Q1/23.
  - As previously announced, the Company made an early repayment in Q4/22 of US$1.0 billion of 2.95% debt securities, originally due January 15, 2023.
- The Company's free cash flow allocation policy that states when net debt is between $10 billion and $15 billion, 50% of free cash flow will be allocated to share repurchases and 50% of free cash flow allocated to the balance sheet less strategic growth / acquisition opportunities. Free cash flow for the purpose of the policy is defined as adjusted funds flow less dividends, less base capital.
- In March 2023, the Company enhanced its free cash flow allocation policy to increase returns to shareholders to 100% of free cash flow when net debt reaches $10 billion. When the net debt level is reached, the policy will be adjusted to define free cash flow as adjusted funds flow less dividends and less total capital expenditures in the year. This is a reflection of the Board of Director's confidence in the sustainability and resilience of the Company to support accelerating incremental shareholder returns to 100% of free cash flow.
- Canadian Natural has diverse, high quality reserves that include significant undeveloped opportunities which support our strong, disciplined growth plan that targets to add capital efficient production across its entire asset base in the near-, mid- and long-term, maximizing value for our shareholders.
- In Q1/23, the Company continued to focus on safe, effective and efficient operations, with quarterly average production volumes of 1,319,391 BOE/d, an increase of 3% over Q1/22 levels.
  - The Company delivered record quarterly average natural gas production of 2,139 MMcf/d in Q1/23, an increase of 133 MMcf/d or 7% over Q1/22 levels, primarily reflecting strong drilling results, partially offset by natural field declines and a third-party pipeline outage.
  - Quarterly average liquids production of 962,908 bbl/d was achieved in Q1/23, an increase of 2% from Q1/22 levels, primarily driven by increased SCO production in the Oil Sands Mining and Upgrading segment.
- The Company's strategic growth plan targets to increase production from our long life no decline oil sands mining and our low decline thermal in situ assets with the following projects:
  - At Horizon, the reliability project is targeting to add approximately 5,000 bbl/d of high value synthetic crude oil ("SCO") capacity in 2023, growing to approximately 14,000 bbl/d in 2025 as a result of shifting the maintenance schedule from once per year to once every two years, reducing downtime for maintenance activities and increasing overall reliability at Horizon.
    - Based on the forward strip as of May 3, 2023, these high margin SCO barrels would capture strong pricing at approximately a US$2.00/bbl premium to WTI for the remainder of 2023, generating significant free cash flow for the Company.
  - Thermal in situ production is targeted to increase in the second half of 2023 and into 2024 with new pads that were drilled in 2022 and pads targeted to be finished drilling in the first half of 2023. Production is targeted to grow by approximately 30,000 bbl/d from Q4/22 to Q4/23 levels, averaging approximately 280,000 bbl/d. This production growth utilizes existing facility capacity with strong capital efficiencies[(4)] ranging from approximately $8,000/bbl/d to $10,000/bbl/d on its Steam Assisted Gravity Drainage ("SAGD") and Cyclic Steam Stimulation ("CSS") pads.

    - With the May 3, 2023 forward strip showing tighter WCS differentials of approximately US$15.50/bbl for the remainder of 2023, an improvement of approximately US$9.00/bbl from Q1/23, these barrels would capture strong pricing and generate significant free cash flow.

- The Company's 2023 capital budget(1) of approximately $5.2 billion remains on track, with targeted base capital(3) of approximately $4.2 billion that is targeted to deliver year over year near-term growth of approximately 70,000 BOE/d, with total 2023 production guidance of approximately 1,330,000 BOE/d to 1,374,000 BOE/d.
  - Budgeted strategic growth capital(3) in 2023 of approximately $1.0 billion is allocated to our long life low decline assets, which targets to add incremental production growth beyond 2023.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023.

(2) Based on sum of rounded numbers.

(3) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023 for more details on net capital expenditures.

(4) Supplementary financial measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release.

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 73% of budgeted total liquids production in 2023, 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 the Company's long life low decline production comes from its top tier thermal in situ oil sands operations and 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 maximize 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	Three Months Ended			
	Mar 31, 2023		Mar 31, 2022	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [(1)]	**88**	**83**	57	56
Natural gas	**26**	**21**	39	23
Dry	**2**	**2**	—	—
Subtotal	**116**	**106**	96	79
Success rate (excluding stratigraphic test / service wells)		**98%**		100%
Stratigraphic test / service wells	**455**	**394**	461	393
Total	**571**	**500**	557	472

(1) Includes bitumen wells.

- The Company drilled a total of 106 net crude oil and natural gas producer wells in Q1/23, representing an increase of 27 net producer wells relative to Q1/22.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs production (bbl/d)	**234,465**	233,371	222,537
Net wells targeting crude oil	**60**	71	44
Net successful wells drilled	**58**	71	44
Success rate	**97%**	100%	100%

- North America E&P liquids production, excluding thermal in situ, averaged 234,465 bbl/d in Q1/23, a 5% increase from Q1/22 levels, primarily reflecting increased activity and strong drilling results on the Company's primary heavy oil assets, partially offset by natural field declines.
    - Primary heavy crude oil production averaged 77,690 bbl/d in Q1/23, a 23% increase from Q1/22 levels, reflecting increased activity and strong drilling results in the Bonnyville/Lloydminster and Clearwater fairways. The Company drilled 42 net primary heavy crude oil wells in Q1/23, of which 26 were multilateral wells.
        - Operating costs[(1)] in the Company's primary heavy crude oil operations averaged $21.47/bbl (US$15.87/bbl) in Q1/23, comparable to Q1/22 levels.
    - Pelican Lake production averaged 48,244 bbl/d in Q1/23, a decrease of 7% from Q1/22 levels, reflecting natural field declines and lower polymer injection rates which were reinstated in February 2023. The field is targeted to return to its historical decline rate of approximately 5% in the second half of 2023.
        - Operating costs at Pelican Lake averaged $9.63/bbl (US$7.12/bbl) in Q1/23, a 29% increase from Q1/22 levels of $7.48/bbl, primarily as a result of higher power costs, as well as higher service costs.
    - North America light crude oil and NGLs production averaged 108,531 bbl/d in Q1/23, comparable to Q1/22 levels, reflecting increased activity offset by natural field declines and a third-party pipeline outage impacting NGLs.
        - Operating costs on the Company's North America light crude oil and NGLs production averaged $18.62/bbl (US$13.77/bbl) in Q1/23, a 22% increase from Q1/22 levels, primarily reflecting higher power as well as service costs.
        - The Company drilled a total of 16 net light crude oil wells in Q1/23 as part of its light oil development plan, which are targeted to come on production in the second half of Q2/23 and the first half of Q3/23.
            - At Wembley, as a part of the program, a 5 well light crude oil pad is targeted to come on production on May 15, 2023 with initial production rates of approximately 4,000 bbl/d of liquids and 14 MMcf/d of natural gas. This pad is part of the Company's budgeted 11 well program in the greater Wembley area in 2023.

Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Bitumen production (bbl/d)	**242,884**	253,188	261,743
Net wells targeting bitumen	**25**	9	12
Net successful wells drilled	**25**	9	12
Success rate	**100%**	100%	100%

(1) Calculated as production expense divided by respective sales volumes. Natural gas and NGLs production volumes approximate sales volumes.

- The Company's thermal in situ production averaged 242,884 bbl/d in Q1/23, a decrease of 7% as targeted, from Q1/22 levels, representing the long life low decline nature of these assets.
  - Thermal in situ operating costs averaged $15.94/bbl (US$11.78/bbl) in Q1/23, an increase of 11% over Q1/22 levels, primarily reflecting higher power costs as well as service costs.
- Canadian Natural continues to deliver safe, reliable production from its long life low decline thermal in situ assets which have decades of strong capital efficient growth opportunities. In 2022, we embarked on a strategic growth plan to increase production, utilizing available facility capacity. Included in this plan are new pads that were drilled in 2022 and pads currently being drilled, which target to add production in the second half of 2023 and beyond.
- Total thermal production in Q4/23 is targeted to average approximately 280,000 bbl/d, representing growth of approximately 30,000 bbl/d from Q4/22 levels, inclusive of natural field declines. A few highlights include:
  - At Primrose, the Company is targeting to grow production by approximately 25,000 bbl/d from Q4/22 to Q4/23 levels, primarily from its two CSS pads drilled in 2022. The first production cycle from these pads is targeted to begin in Q3/23, driving strong quarterly production at Primrose to approximately 100,000 bbl/d in Q4/23.
  - At Kirby, the Company is targeting to grow production by approximately 15,000 bbl/d from Q4/22 levels to approximately 65,000 bbl/d in Q4/23, as the Company progresses with the development of four SAGD pads in 2023. Production from the first pad which was drilled in 2022 is targeted to ramp up to full production capacity in Q3/23. The three remaining pads are targeted to ramp up to full production capacity over the first nine months of 2024, at a pace of one pad per quarter.
  - At Jackfish, production has been very strong since acquiring the asset in 2019, averaging approximately 115,000 bbl/d, with minimal capital invested. Two SAGD pads are currently being drilled, with production from these pads targeted to ramp up to their full production capacities in Q3/24 and Q4/24 respectively, supporting continued high utilization rates.
- Subsequent to quarter end, the Company commenced planned turnarounds at Primrose East and Wolf Lake, which are targeted to impact Q2/23 production volumes by approximately 15,000 bbl/d and are reflected in the Company's previously announced annual production guidance.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain of its thermal in situ assets with an objective to increase bitumen production, reduce the Steam to Oil Ratio ("SOR"), reduce GHG intensity and realize high solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - After a successful solvent pilot at Kirby South, the Company has substantially completed engineering and design of a commercial scale solvent SAGD pad development at Kirby North. The solvent facility module installations are targeted to begin in Q3/23, followed by solvent injection targeted for mid-2024.
  - At Primrose, the Company is currently piloting solvent enhanced oil recovery in the steam flood area and is targeting SOR and GHG intensity reductions of 40% to 45%, with solvent recovery greater than 70%. Results to date have been positive and the Company targets to complete the pilot in Q4/23.

North America Natural Gas

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Natural gas production (MMcf/d)	**2,127**	2,105	1,988
Net wells targeting natural gas	**21**	15	23
Net successful wells drilled	**21**	15	23
Success rate	**100%**	100%	100%

- Canadian Natural achieved record quarterly natural gas production in North America in Q1/23, averaging 2,127 MMcf/d, an increase of 139 MMcf/d or 7% over Q1/22 levels, reflecting strong drilling results from its liquids-rich Montney and Deep Basin wells, partially offset by natural field declines and a third-party pipeline outage. The Company, as part of its natural gas development plan, drilled 21 net wells in Q1/23, with 19 net wells brought on production during the quarter.

- North America natural gas operating costs averaged $1.43/Mcf in Q1/23, an increase of 12% over Q1/22 levels, primarily reflecting higher service costs.
- On January 18, 2023, a third-party pipeline outage occurred, which impacted the Company's Q1/23 production by approximately 9,000 BOE/d (33 MMcf/d and 3,500 bbl/d). The third-party operator is targeting the pipeline to resume full service before the end of May 2023.

International Exploration and Production

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil production (bbl/d)	**27,331**	26,915	31,703
Natural gas production (MMcf/d)	**12**	10	18
Net wells targeting crude oil	**—**	—	—
Net successful wells drilled	**—**	—	—
Success rate	—%	—%	—%

- International E&P crude oil production volumes averaged 27,331 bbl/d in Q1/23, a decrease of 14% from Q1/22 levels, primarily reflecting natural field declines and maintenance activities in Q1/23.

North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Synthetic crude oil production (bbl/d) [(1)(2)]	**458,228**	428,784	429,826

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

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

- Canadian Natural continues to focus on safe, reliable, effective and efficient operations of its world class Oil Sands Mining and Upgrading assets to deliver high value SCO, with production averaging 458,228 bbl/d in Q1/23, an increase of 7% from Q1/22 levels. The Company completed the previously announced mining equipment repairs in January 2023 and subsequently, production returned to normal rates.
  - Oil Sands Mining and Upgrading operating costs remain top tier, averaging $25.06/bbl (US$18.53/bbl) in Q1/23, comparable to Q1/22 levels.
- The Company realized strong SCO pricing averaging $96.07/bbl in Q1/23, capturing a US$2.07/bbl premium to WTI, generating significant free cash flow for the Company.
  - Approximately 47% of the Company's budgeted total liquids production in 2023 consists of high value SCO, which, based on the forward strip as of May 3, 2023, would capture a price premium of approximately US$2.00/bbl to WTI throughout the remainder 2023.
- At Horizon, the Company is progressing with its reliability enhancement project, which is targeted to be 45 days ahead of schedule, as previously announced. This project targets to extend the major maintenance cycle from once per year to once every second year, increasing the SCO production capacity by approximately 5,000 bbl/d in 2023 and increasing to approximately 14,000 bbl/d in 2025, increasing overall reliability at Horizon.
- As previously announced and included in the Company's 2023 production guidance, planned turnaround activities at the Company's Oil Sands Mining and Upgrading operations include:
  - A major turnaround at the non-operated Scotford Upgrader began on April 10, 2023, with the mines targeted to operate at reduced rates for approximately 73 days, impacting 2023 annual production by approximately 8,300 bbl/d.
  - A turnaround at Horizon is targeted to begin on May 16, 2023 with a full plant outage targeted for approximately 28 days, impacting 2023 annual production by approximately 21,600 bbl/d. During this time, the Company is planning to complete tie ins supporting the reliability enhancement project.

MARKETING

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs			
WTI benchmark price (US$/bbl) (1)	**$ 76.11**	$ 82.62	$ 94.38
WCS heavy differential as a percentage of WTI (%) (2)	**33%**	31%	15%
SCO benchmark price (US$/bbl)	**$ 78.18**	$ 86.78	$ 93.05
Condensate benchmark price (US$/bbl)	**$ 79.83**	$ 83.33	$ 96.16
Exploration & Production liquids realized pricing (C$/bbl) (3)(4)	**$ 58.85**	$ 69.34	$ 93.54
SCO realized pricing (C$/bbl) (4)(5)	**$ 96.07**	$ 103.79	$ 112.05
Natural gas			
AECO benchmark price (C$/GJ)	**$ 4.12**	$ 5.29	$ 4.35
Natural gas realized pricing (C$/Mcf) (5)	**$ 4.27**	$ 6.39	$ 5.26

(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 excludes risk management activities.

(4) Non-GAAP ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023.

(5) Pricing is net of blending costs and excludes risk management activities.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, thermal in situ bitumen and SCO.
- Global benchmark crude oil prices continue to be at levels where the Company can generate strong returns. Prices do remain volatile as a result of geopolitical factors and demand concerns driven by an increased risk of a global recession due to persistent inflation and rising interest rates. WTI prices remained strong in Q1/23, averaging US$76.11/bbl in Q1/23, however this represents decreases of 19% and 8% from Q1/22 and Q4/22 respectively.
- SCO benchmark pricing continued to represent a price premium of US$2.07/bbl to WTI as a result of strong North American demand for refined products, with the SCO benchmark price averaging US$78.18/bbl in Q1/23.
  - Approximately 47% of the Company's budgeted total liquids production in 2023 consists of high value SCO, which as of the May 3, 2023 forward strip, would capture a premium to WTI of approximately US$2.00/bbl throughout 2023.
- The narrowing of the WCS heavy differential to-date in 2023 relative to Q4/22 and the early part of Q1/23 reflects the completion of the US Strategic Petroleum Reserve ("SPR") releases and the return of certain refineries in the US Midwest, strengthening margins on the Company's heavy crude oil production.
  - The forward strip as of May 3, 2023 forecasts the WCS differential to remain relatively narrow throughout the remainder 2023, at approximately US$15.50/bbl, an improvement of approximately US$9.00/bbl from Q1/23 levels.
- The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 85,376 BOE/d in Q1/23, on which the NWR realized strong margins on domestic diesel volumes.
- Canadian Natural has diversified sales points to limit exposure to any one particular market and maximize value for our shareholders. Based on the mid-point of the Company's 2023 production guidance, the Company will use natural gas in its operations equivalent to approximately 36% of its natural gas production, with approximately 28% of its natural gas production sold at AECO/Station 2 pricing, and approximately 36% exported to other North American and international markets.
  - The monthly AECO natural gas benchmark price averaged $4.12/GJ in Q1/23, a 5% decrease from Q1/22 and a 22% decrease from Q4/22. Weaker natural gas prices primarily reflect increased North American production and higher storage levels due to seasonally mild weather and lower heating demand.

- On January 18, 2023, a third-party pipeline outage occurred, which impacted the Company's Q1/23 production by approximately 9,000 BOE/d (33 MMcf/d and 3,500 bbl/d). The third-party operator is targeting the pipeline to resume full service before the end of May 2023.
- Canadian Natural has been a supporter of incremental pipeline projects to ensure Canadian crude oil and natural gas can access global markets to deliver the most responsible and leading ESG production that the world needs.
  - On March 10, 2023, Trans Mountain Corporation provided an update on its 590,000 bbl/d Trans Mountain Expansion project, on which Canadian Natural has committed 94,000 bbl/d. Trans Mountain Corporation now anticipates mechanical completion of the pipeline to occur at the end of 2023 with commercial service expected to occur in Q1/24. Trans Mountain Corporation now estimates the total cost of this project to be approximately $30.9 billion.

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 flexible capital expenditure program all support a strong financial position and provide the appropriate financial resources for the near-, mid- and long-term.

- Safe, effective and efficient operations combined with our high quality, long life low decline asset base generated quarterly free cash flow of approximately $1.4 billion after dividend payments of approximately $0.9 billion and base capital expenditures of approximately $1.1 billion (excluding net acquisitions and strategic growth capital of approximately $0.28 billion in the quarter, as per the Company's free cash flow allocation policy).
- Canadian Natural's free cash flow allocation policy states that when net debt is between $10 billion and $15 billion, 50% of free cash flow will be allocated to share repurchases and 50% to the balance sheet less strategic growth / acquisition opportunities. Free cash flow for the purpose of the policy is defined as adjusted funds flow less dividends, less base capital.
- In March 2023, the Company enhanced its free cash flow allocation policy to increase returns to shareholders to 100% of free cash flow when net debt reaches $10 billion. When the net debt level is reached, the policy will be adjusted to define free cash flow as adjusted funds flow less dividends and less total capital expenditures in the year. This is a reflection of the Board of Director's confidence in the sustainability and resilience of the Company to support accelerating incremental shareholder returns to 100% of free cash flow.
- Returns to shareholders in Q1/23 were strong, totaling approximately $1.6 billion, comprised of approximately $0.9 billion of dividends and approximately $0.7 billion of share repurchases.
  - Canadian Natural increased its sustainable and growing quarterly dividend in March 2023 to $0.90 per common share, up 6% from $0.85 per common share, marking 2023 as the 23rd consecutive year of dividend increases and demonstrating the confidence that the Board of Directors has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline asset base.
  - In Q1/23, the Company repurchased approximately 8.9 million common shares for cancellation at a weighted average price of $76.96 per share for a total of approximately $0.7 billion.
  - In March 2023, the Company renewed its Normal Course Issuer Bid ("NCIB") which states that during the 12 month period commencing March 13, 2023 and ending March 12, 2024, the Company can repurchase for cancellation up to 10% of the public float (determined in accordance with the rules of the TSX), up to a maximum of approximately 92.3 million common shares.
- Canadian Natural continues to maintain a strong balance sheet and financial flexibility, with approximately $11.9 billion in net debt and significant liquidity of approximately $6.1 billion at the end of Q1/23.
  - As previously announced, the Company made an early repayment in Q4/22 of US$1.0 billion of 2.95% debt securities, originally due January 15, 2023.
  - Undrawn revolving bank credit facilities totaling approximately $5.5 billion were available at March 31, 2023. Including cash and cash equivalents and short-term investments, the Company had significant liquidity of approximately $6.1 billion. At March 31, 2023, the Company had $588 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

- Year-to-date, up to and including May 3, 2023, the Company has returned approximately $2.8 billion to shareholders through approximately $1.9 billion in dividends and $0.9 billion through the repurchase and cancellation of approximately 11.1 million common shares.
- Subsequent to quarter end, the Company declared a quarterly dividend of $0.90 per share, payable on July 5, 2023 to shareholders of record on June 16, 2023.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE HIGHLIGHTS

Canada and Canadian Natural are well positioned to deliver affordable, reliable, safe and responsibly produced energy that the world needs, through leading ESG performance. Canadian Natural's diverse portfolio is supported by a large amount of long life low decline assets which have low risk, high value reserves that require low maintenance capital. This allows us to remain flexible with our capital allocation and creates an ideal opportunity to pilot and apply technologies for GHG emissions reductions. Canadian Natural continues to invest in a range of technologies to reduce emissions, such as solvents for enhanced recovery and carbon capture, utilization and storage ("CCUS") projects. Our culture of continuous improvement provides a significant advantage to delivering on our strategy of investing in GHG technologies across our assets, including opportunities for methane emissions reduction, which will enhance the Company’s environmental performance and long-term sustainability.

Environmental Targets

Canadian Natural is committed to reducing its environmental footprint and as previously announced, has committed to the following environmental targets:

- 40% reduction in corporate Scope 1 and Scope 2 absolute GHG emissions by 2035, from a 2020 baseline
- 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

Canadian Natural is an industry leader in abandonment and reclamation activity and through its active program, the Company has abandoned more than 3,000 wells per year in each of the last two years. At this pace, the Company would be able to achieve 100% abandonment of its current inventory of inactive wells in approximately 10 years.

Pathways Alliance

The six major oil sands companies in the Pathways Alliance ("Pathways"), including Canadian Natural, operate approximately 95% of Canada’s oil sands production. The goal of this unique alliance is to support Canada in meeting its climate commitments and position Canada to be the preferred source of crude oil globally. Working collectively with the federal and provincial governments, Pathways has a goal to achieve net zero GHG emissions from oil sands operations by 2050 and is pursuing realistic and workable solutions to deliver significant emissions reductions.

Pathways recognizes that there are multiple technologies towards achieving net zero emissions in the oil sands, including the deployment of existing and emerging GHG reduction technologies such as direct air capture, clean hydrogen, process improvements, energy efficiency, fuel switching and electrification. The anchor project is a CO_2 trunkline connecting Fort McMurray and Cold Lake to a carbon sequestration hub. In January 2023, Pathways entered into a Carbon Sequestration Evaluation Agreement with the Government of Alberta, enabling Pathways to conduct a detailed evaluation of the proposed geological storage hub to safely inject and permanently store CO_2. Members of Pathways continue to advance environmental field programs to minimize the project’s environmental disturbance. Additionally, detailed engineering design and a subsurface development plan is ongoing, including evaluation of data from two water injection test wells to refine our understanding of storage capability and capacity, and ensure safe, effective and efficient CO_2 sequestration.

The proposed carbon storage hub would be one of the world's largest carbon capture and storage projects and would be connected to a transportation line that would initially gather captured CO_2 from an anticipated 14 oil sands facilities in the Fort McMurray, Christina Lake and Cold Lake regions. The plan is to grow the transportation network to include over 20 oil sands facilities, and to accommodate other industries in the region interested in CCS. Stakeholder engagement continues to progress with Indigenous and local communities in northern Alberta related to the Pathways CCS project.

Government Support for Emissions Reductions and Carbon Capture, Utilization and Storage ("CCUS")

Canadian Natural is a leader in CCUS and GHG reduction projects and sees many opportunities to work collaboratively with industry peers and governments to advance investments in CCUS and to achieve meaningful GHG emissions reductions in support of Canada's climate goals. The Government of Canada has proposed an investment tax credit for CCUS projects in Canada. The Government of Alberta's 2023 Budget announcement on February 28, 2023 included support for CCUS projects and coordination with federal CCUS initiatives.

In addition, the Government of Alberta released its Emissions Reduction and Energy Development Plan ("ERED") on April 19, 2023, which outlines the importance of ensuring a globally competitive oil and natural gas industry while reducing emissions and an aspiration to achieve net zero by 2050. By working together, industry and governments have the opportunity to help achieve climate goals, meet economic objectives and support Canada's role in energy security.

Blueberry River First Nations

In January 2023, the British Columbia Government came to a resolution with the Blueberry River First Nations ("BRFN") regarding the impact of resource development on the BRFN lands. The Company continues to receive a number of permits and is progressing its targeted activities in 2023. Engagement is ongoing with government and the regulator to understand the implementation of its land management framework and the impacts to Canadian Natural going forward. The Company values its relationships with local First Nation communities, including the BRFN, and meets regularly with communities to build and maintain positive relationships in order to create shared value and mutual benefit from our operations.

Governance

Canadian Natural believes in diversity and values the benefits that a diverse workforce can bring to the entire organization. Diversity promotes the inclusion of different perspectives and ideas, mitigates against group bias and ensures that the Company has the opportunity to benefit from all available talent and ideas. The Board of Directors supports diversity in all its forms and in sufficient numbers to bring a wide range of perspectives to its decision making processes. Director nominees are selected for their ability to exercise independent judgment, experience and expertise and their individual diversity of gender, background, experience and skills is always considered. The Board of Directors believes that a Board composition where a minimum of 40% of its independent directors and a minimum of 30% of all directors are women, reflects appropriate gender diversity when the other factors relevant to Board effectiveness are considered.

ADVISORY

Special Note Regarding Non-GAAP and Other Financial Measures

This press release includes references to non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this press release, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023.

Free Cash Flow

Free cash flow is a non-GAAP financial measure that represents adjusted funds flow adjusted for base 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.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Adjusted funds flow [(1)]	**$ 3,429**	$ 4,176	$ 4,975
Less: Base capital expenditures [(2)]	**1,117**	850	844
Dividends on common shares	**938**	834	689
Free cash flow	**$ 1,374**	$ 2,492	$ 3,442

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023..

(2) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of Company's MD&A for the three months ended March 31, 2023, dated May 3, 2023 for more details on net capital expenditures.

Capital Budget

Capital budget is a forward looking non-GAAP financial measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

Long-term Debt, net

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents.

Capital Efficiency

Capital efficiency is a supplementary financial measure that represents the capital spent to add new or incremental production divided by the current rate of the new or incremental production. It is expressed as a dollar amount per flowing volume of a product ($/bbl/d or $/BOE/d). The Company considers capital efficiency a key measure in evaluating its performance, as it demonstrates the efficiency of the Company's capital investments.

Break-even WTI Price

The break-even WTI price is a supplementary financial measure that represents the equivalent US dollar WTI price per barrel where the Company's adjusted funds flow is equal to the sum of maintenance capital and dividends. The Company considers the break-even WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The break-even WTI price incorporates the non-GAAP financial measure adjusted funds flow as reconciled in the "Non-GAAP and Other Financial Measures" section of the Company's MD&A. Maintenance capital is a supplementary financial measure that represents the capital required to maintain annual production at prior period levels.

ADVISORY

Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, income tax expenses, and other 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"), the Primrose thermal oil projects, the Pelican Lake water and polymer flood projects, the Kirby Thermal Oil Sands Project, the Jackfish Thermal Oil Sands Project and 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; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the impact of the Pathways Alliance ("Pathways") initiative and activities, government support for Pathways and the ability to achieve net zero emissions from oil production, 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 the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of the Russian invasion of Ukraine, continuing effects of the novel coronavirus ("COVID-19") pandemic, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; 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; the Company's ability to implement strategies and leverage technologies to meet climate change initiatives and emissions targets; the 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; 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; 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 and Other Financial Measures

This MD&A includes references to non-GAAP measures, which include non-GAAP and other financial measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("NI 52-112"). Non-GAAP measures are used by the Company to evaluate its financial performance, financial position or cash flow. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided in the "Non-GAAP and Other Financial Measures" section of this MD&A.

Special Note Regarding Currency, Financial Information and Production

This MD&A should be read in conjunction with the Company's unaudited interim consolidated financial statements (the "financial statements") for the three months ended March 31, 2023 and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2022. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months ended March 31, 2023 and this MD&A have been prepared in accordance with International Financial Reporting Standards ("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 months ended March 31, 2023 in relation to the first quarter of 2022 and the fourth quarter of 2022. 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, 2022, 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 May 3, 2023.

FINANCIAL HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Product sales [1]	**$ 9,548**	$ 11,012	$ 12,132
Crude oil and NGLs	**$ 8,412**	$ 9,508	$ 10,773
Natural gas	**$ 851**	$ 1,287	$ 1,002
Net earnings	**$ 1,799**	$ 1,520	$ 3,101
Per common share – basic	**$ 1.63**	$ 1.37	$ 2.66
– diluted	**$ 1.62**	$ 1.36	$ 2.63
Adjusted net earnings from operations [2]	**$ 1,881**	$ 2,194	$ 3,376
Per common share – basic [3]	**$ 1.71**	$ 1.98	$ 2.90
– diluted [3]	**$ 1.69**	$ 1.96	$ 2.86
Cash flows from operating activities	**$ 1,295**	$ 4,544	$ 2,853
Adjusted funds flow [2]	**$ 3,429**	$ 4,176	$ 4,975
Per common share – basic [3]	**$ 3.12**	$ 3.78	$ 4.27
– diluted [3]	**$ 3.08**	$ 3.73	$ 4.21
Cash flows used in investing activities	**$ 1,153**	$ 1,262	$ 1,251
Net capital expenditures [2]	**$ 1,394**	$ 1,317	$ 1,455

(1) Further details related to product sales are disclosed in note 17 to the financial statements.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the first quarter of 2023 were $1,799 million compared with $3,101 million for the first quarter of 2022, and $1,520 million for the fourth quarter of 2022. Net earnings for the first quarter of 2023 included non-operating items, net of tax, of $82 million compared with $275 million for the first quarter of 2022 and $674 million for the fourth quarter of 2022 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss (gain) from investments, a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea in the fourth quarter of 2022, and government grant income under the provincial well-site rehabilitation programs. Excluding these items, adjusted net earnings from operations for the first quarter of 2023 were $1,881 million compared with $3,376 million for the first quarter of 2022 and $2,194 million for the fourth quarter of 2022.

The decrease in adjusted net earnings from operations for the first quarter of 2023 from the comparable periods primarily reflected:

- lower crude oil and NGLs netbacks [1] and crude oil and NGLs sales volumes in the Exploration and Production segments; and
- lower SCO pricing [1] in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment.

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

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the first quarter of 2023 were $1,295 million compared with $2,853 million for the first quarter of 2022 and $4,544 million for the fourth quarter of 2022. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2023 was $3,429 million compared with $4,975 million for the first quarter of 2022 and $4,176 million for the fourth quarter of 2022. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from 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.

Production Volumes

Crude oil and NGLs production before royalties for the first quarter of 2023 increased 2% to 962,908 bbl/d from 945,809 bbl/d for the first quarter of 2022, and increased 2% from 942,258 bbl/d for the fourth quarter of 2022. Natural gas production before royalties for the first quarter of 2023 increased 7% to 2,139 MMcf/d from 2,006 MMcf/d for the first quarter of 2022 and was comparable with 2,115 MMcf/d for the fourth quarter of 2022. Total production before royalties for the first quarter of 2023 of 1,319,391 BOE/d increased 3% from 1,280,180 BOE/d for the first quarter of 2022, and was comparable with 1,294,679 BOE/d for the fourth quarter of 2022. Crude oil and NGLs and natural gas production volumes are discussed in detail in the "Daily Production, before royalties" section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices (1) averaged $58.85 per bbl for the first quarter of 2023, a decrease of 37% from $93.54 per bbl for the first quarter of 2022, and a decrease of 15% from $69.34 per bbl for the fourth quarter of 2022. The realized natural gas price decreased 19% to average $4.27 per Mcf for the first quarter of 2023 from $5.26 per Mcf for the first quarter of 2022, and decreased 33% from $6.39 per Mcf for the fourth quarter of 2022. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 14% to average $96.07 per bbl for the first quarter of 2023 from $112.05 per bbl for the first quarter of 2022, and decreased 7% from $103.79 per bbl for the fourth quarter of 2022. 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", "Realized 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 (2) averaged $16.93 per bbl for the first quarter of 2023, an increase of 7% from $15.80 per bbl for the first quarter of 2022, and a decrease of 17% from $20.37 per bbl for the fourth quarter of 2022. Natural gas production expense (2) averaged $1.47 per Mcf for the first quarter of 2023, an increase of 12% from $1.31 per Mcf for the first quarter of 2022 and an increase of 18% from $1.25 per Mcf for the fourth quarter of 2022. In the Oil Sands Mining and Upgrading segment, production expense (2) averaged $25.06 per bbl for the first quarter of 2023, comparable to $24.60 per bbl for the first quarter of 2022, and $25.48 per bbl for the fourth quarter of 2022. 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.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(2) Calculated as respective production expense divided by respective sales volumes.

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)	**Mar 31 2023**	Dec 31 2022	Sep 30 2022	Jun 30 2022
Product sales [(1)]	**$ 9,548**	$ 11,012	$ 12,574	$ 13,812
Crude oil and NGLs	**$ 8,412**	$ 9,508	$ 11,001	$ 11,727
Natural gas	**$ 851**	$ 1,287	$ 1,342	$ 1,605
Net earnings	**$ 1,799**	$ 1,520	$ 2,814	$ 3,502
Net earnings per common share				
– basic	**$ 1.63**	$ 1.37	$ 2.52	$ 3.04
– diluted	**$ 1.62**	$ 1.36	$ 2.49	$ 3.00

($ millions, except per common share amounts)	Mar 31 2022	Dec 31 2021	Sep 30 2021	Jun 30 2021
Product sales [(1)]	$ 12,132	$ 10,190	$ 8,521	$ 7,124
Crude oil and NGLs	$ 10,773	$ 8,979	$ 7,607	$ 6,382
Natural gas	$ 1,002	$ 958	$ 694	$ 509
Net earnings	$ 3,101	$ 2,534	$ 2,202	$ 1,551
Net earnings per common share				
– basic	$ 2.66	$ 2.16	$ 1.87	$ 1.31
– diluted	$ 2.63	$ 2.14	$ 1.86	$ 1.30

(1) Further details related to product sales for the three months ended March 31, 2023 and 2022 are disclosed in note 17 to the financial statements.

Volatility in the quarterly net earnings 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, and the impact of the Russian invasion of Ukraine 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; and the impact of the differential between WTI and Dated Brent ("Brent") benchmark pricing in the International segments.
- **Natural gas pricing** – The impact of fluctuations in both the demand for natural gas and inventory storage levels, third-party pipeline maintenance and outages, the impact of geopolitical and market uncertainties, the impact of seasonal conditions, and the impact of shale gas production in the US.
- **Crude oil and NGLs sales volumes** – Fluctuations in production from the Kirby and Jackfish Thermal Oil Sands Projects, fluctuations in production due to the cyclic nature of the Primrose thermal oil projects, fluctuations in the Company's drilling program in North America and the International segments, natural decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, 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 drilling program in North America and the International segments, natural decline rates, the temporary shutdown and subsequent reinstatement of the Pine River Gas Plant during 2021, and the impact and timing of acquisitions.
- **Production expense** – Fluctuations primarily due to the impacts of the demand and cost for services, fluctuations in product mix and production volumes, seasonal conditions, increased carbon tax and energy costs, inflationary cost pressures, cost optimizations across all segments, the impact and timing of acquisitions, turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and maintenance activities in the International segments.

- **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, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, and a recoverability charge relating to the de-booking of reserves at the Ninian field in the North Sea.
- **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 and accrued interest on the deferred Petroleum Revenue Tax ("PRT") recovery.
- **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. Realized and unrealized foreign exchange gains and losses are also recorded with respect to US dollar denominated debt, partially offset by the impact of any cross currency swap hedges outstanding.
- **Gain on acquisitions, loss (gain) from investments, and income from North West Redwater Partnership ("NWRP")** – Fluctuations due to the recognition of gains on acquisitions, loss (gain) from the investments in PrairieSky Royalty Ltd. and Inter Pipeline Ltd. shares, and the distribution from NWRP in the second quarter of 2021.

BUSINESS ENVIRONMENT

Global benchmark crude oil prices continued to reflect conditions seen in the second half of 2022, including demand concerns related to rising interest rates in response to persistent inflation, and concerns of a global recession. Pricing also continued to be impacted by geopolitical factors such as the Russian invasion of Ukraine. Global crude oil supply outstripped demand in the first quarter of 2023, with Russian crude supply, as well as withdrawals from the US Strategic Petroleum Reserve through the end of 2022.

Liquidity

As at March 31, 2023, the Company had undrawn revolving bank credit facilities of $5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,096 million in liquidity (1). The Company also has certain other dedicated credit facilities supporting letters of credit.

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.

Risks and Uncertainties

The global economy, including Canada, is experiencing higher and more persistent inflation, in part due to the Russian invasion of Ukraine and ongoing supply constraints due to the continuing impacts of COVID-19. As a result of these conditions, the Company has experienced and may continue to experience higher than normal fluctuations in commodity prices and interest rates, and may experience inflationary pressures on its operating and capital expenditures.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

Benchmark Commodity Prices

	Three Months Ended		
(Average for the period)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
WTI benchmark price (US$/bbl)	**$ 76.11**	$ 82.62	$ 94.38
Dated Brent benchmark price (US$/bbl)	**$ 81.24**	$ 88.15	$ 99.17
WCS Heavy Differential from WTI (US$/bbl)	**$ 24.74**	$ 25.65	$ 14.60
SCO price (US$/bbl)	**$ 78.18**	$ 86.78	$ 93.05
Condensate benchmark price (US$/bbl)	**$ 79.83**	$ 83.33	$ 96.16
Condensate Differential from WTI (US$/bbl)	**$ (3.72)**	$ (0.71)	$ (1.78)
NYMEX benchmark price (US$/MMBtu)	**$ 3.43**	$ 6.27	$ 4.91
AECO benchmark price (C$/GJ)	**$ 4.12**	$ 5.29	$ 4.35
US/Canadian dollar average exchange rate (US$)	**$ 0.7393**	$ 0.7366	$ 0.7899

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 directly impacted by fluctuations in foreign exchange rates, and its product revenues 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$76.11 per bbl for the first quarter of 2023, a decrease of 19% from US$94.38 per bbl for the first quarter of 2022, and a decrease of 8% from US$82.62 per bbl for the fourth quarter of 2022.

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$81.24 per bbl for the first quarter of 2023, a decrease of 18% from US$99.17 per bbl for the first quarter of 2022, and a decrease of 8% from US$88.15 per bbl for the fourth quarter of 2022.

The decrease in WTI and Brent pricing for the first quarter of 2023 from the comparable periods primarily reflected continuing demand concerns related to rising interest rates in response to persistent inflation and concerns of a global recession.

The WCS Heavy Differential averaged US$24.74 per bbl for the first quarter of 2023, compared to US$14.60 per bbl for the first quarter of 2022 and US$25.65 per bbl for the fourth quarter of 2022. The widening of the WCS Heavy Differential for the first quarter of 2023 from the first quarter of 2022 primarily reflected lower US Gulf Coast pricing and continued withdrawals from the US Strategic Petroleum Reserve through the end of 2022. The slight narrowing of the WCS Heavy Differential for the first quarter of 2023 from the fourth quarter of 2022 primarily reflected the completion of US Strategic Petroleum Reserve releases and the restart of certain refineries in the US Midwest.

The SCO price averaged US$78.18 per bbl for the first quarter of 2023, a decrease of 16% from US$93.05 per bbl for the first quarter of 2022, and a decrease of 10% from US$86.78 per bbl for the fourth quarter of 2022. The decrease in SCO pricing for the first quarter of 2023 from the comparable periods primarily reflected the decrease in WTI benchmark pricing as well as weakening diesel fuel crack spreads.

NYMEX natural gas prices averaged US$3.43 per MMBtu for the first quarter of 2023, a decrease of 30% from US$4.91 per MMBtu for the first quarter of 2022, and a decrease of 45% from US$6.27 per MMBtu for the fourth quarter of 2022. The decrease in NYMEX natural gas prices for the first quarter of 2023 from the first quarter of 2022 primarily reflected increased North American production and higher storage levels due to seasonally mild winter weather and lower heating demand. The decrease in NYMEX natural gas prices for the first quarter of 2023 from the fourth quarter of 2022 primarily reflected lower storage draws due to mild winter weather, combined with increased production in North America. Additionally, the restart of the Freeport LNG facility was delayed until late in the first quarter of 2023.

AECO natural gas prices averaged $4.12 per GJ for the first quarter of 2023, a decrease of 5% from $4.35 per GJ for the first quarter of 2022, and a decrease of 22% from $5.29 per GJ for the fourth quarter of 2022. The decrease in AECO natural gas prices for the first quarter of 2023 from the comparable periods primarily reflected NYMEX benchmark pricing, and increased production levels in the Western Canadian Sedimentary Basin.

DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**477,349**	486,559	484,280
North America – Oil Sands Mining and Upgrading (1)	**458,228**	428,784	429,826
International – Exploration and Production			
North Sea	**13,240**	14,006	15,961
Offshore Africa	**14,091**	12,909	15,742
Total International (2)	**27,331**	26,915	31,703
Total Crude oil and NGLs	**962,908**	942,258	945,809
Natural gas (MMcf/d) (3)			
North America	**2,127**	2,105	1,988
International			
North Sea	**3**	3	3
Offshore Africa	**9**	7	15
Total International	**12**	10	18
Total Natural gas	**2,139**	2,115	2,006
Total Barrels of oil equivalent (BOE/d)	**1,319,391**	1,294,679	1,280,180
Product mix			
Light and medium crude oil and NGLs	**10%**	11%	11%
Pelican Lake heavy crude oil	**4%**	4%	4%
Primary heavy crude oil	**6%**	5%	5%
Bitumen (thermal oil)	**18%**	20%	20%
Synthetic crude oil (1)	**35%**	33%	34%
Natural gas	**27%**	27%	26%
Percentage of gross revenue (1) (4) (5)			
Crude oil and NGLs	**90%**	87%	91%
Natural gas	**10%**	13%	9%

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

(2) "International" includes North Sea and Offshore Africa Exploration and Production segments in all instances used.

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs (bbl/d)			
North America – Exploration and Production	**396,482**	381,546	386,621
North America – Oil Sands Mining and Upgrading	**411,434**	372,894	376,984
International – Exploration and Production			
North Sea	**13,240**	13,985	15,908
Offshore Africa	**12,740**	11,153	15,010
Total International	**25,980**	25,138	30,918
Total Crude oil and NGLs	**833,896**	779,578	794,523
Natural gas (MMcf/d)			
North America	**1,988**	1,937	1,829
International			
North Sea	**3**	3	3
Offshore Africa	**9**	6	14
Total International	**12**	9	17
Total Natural gas	**2,000**	1,946	1,846
Total Barrels of oil equivalent (BOE/d)	**1,167,300**	1,103,833	1,102,221

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

Crude oil and NGLs production before royalties for the first quarter of 2023 averaged 962,908 bbl/d, an increase of 2% from 945,809 bbl/d for the first quarter of 2022, and an increase of 2% from 942,258 bbl/d for the fourth quarter of 2022. The increase in crude oil and NGLs production for the first quarter of 2023 as compared to the prior periods primarily reflected increased production in the Oil Sands Mining and Upgrading segment, partially offset by decreased thermal oil production.

Annual crude oil and NGLs production before royalties for 2023 is targeted to average between 969,000 bbl/d and 1,001,000 bbl/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Record natural gas production before royalties for the first quarter of 2023 of 2,139 MMcf/d increased 7% from 2,006 MMcf/d for the first quarter of 2022, and was comparable with 2,115 MMcf/d for the fourth quarter of 2022. The increase in natural gas production for the first quarter of 2023 from the first quarter of 2022 primarily reflected strong drilling results, partially offset by a third-party pipeline outage and natural field declines.

Annual natural gas production before royalties for 2023 is targeted to average between 2,170 MMcf/d and 2,242 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 first quarter of 2023 averaged 477,349 bbl/d, which was comparable with 484,280 bbl/d for the first quarter of 2022, and decreased 2% from 486,559 bbl/d for the fourth quarter of 2022. Crude oil and NGLs production for the first quarter of 2023 as compared to the prior periods primarily reflected natural field declines in thermal, offset by drilling activity in conventional E&P.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 242,884 bbl/d for the first quarter of 2023, a decrease of 7% from 261,743 bbl/d for the first quarter of 2022 and a decrease of 4% from 253,188 bbl/d for the fourth quarter of 2022, primarily reflecting natural field declines.

Pelican Lake heavy crude oil production before royalties averaged 48,244 bbl/d for the first quarter of 2023, a decrease of 7% from 51,991 bbl/d for the first quarter of 2022, and comparable with 48,221 bbl/d for the fourth quarter of 2022, demonstrating Pelican Lake's long life low decline production.

Record natural gas production before royalties for the first quarter of 2023 averaged 2,127 MMcf/d, an increase of 7% from 1,988 MMcf/d for the first quarter of 2022, and comparable with 2,105 MMcf/d for the fourth quarter of 2022. The increase in natural gas production for the first quarter of 2023 from the first quarter of 2022 primarily reflected strong drilling results, partially offset by a third-party pipeline outage and natural field declines.

North America – Oil Sands Mining and Upgrading

SCO production before royalties for the first quarter of 2023 of 458,228 bbl/d increased 7% from 429,826 bbl/d for the first quarter of 2022 primarily reflecting facility restrictions at the Scotford Upgrader during the first quarter of 2022. SCO production before royalties increased 7% from 428,784 bbl/d for the fourth quarter of 2022, primarily reflecting the reinstatement of production volumes following unplanned outages in the fourth quarter of 2022 and the completion of related mining equipment repairs in January 2023.

International – Exploration and Production

International crude oil and NGLs production before royalties for the first quarter of 2023 of 27,331 bbl/d decreased 14% from 31,703 bbl/d for the first quarter of 2022, and was comparable with 26,915 bbl/d for the fourth quarter of 2022. The decrease from the first quarter of 2022 primarily reflected natural field declines, together with the impact 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)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
International	**1,912,388**	390,959	872,196

During the first quarter of 2023, there were no crude oil liftings from the Company's platforms in the North Sea.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs ($/bbl) [1]			
Realized price [2]	**$ 58.85**	$ 69.34	$ 93.54
Transportation [2]	**4.52**	4.11	4.18
Realized price, net of transportation [2]	**54.33**	65.23	89.36
Royalties [3]	**10.09**	13.56	17.80
Production expense [4]	**16.93**	20.37	15.80
Netback [2]	**$ 27.31**	$ 31.30	$ 55.76
Natural gas ($/Mcf) [1]			
Realized price [5]	**$ 4.27**	$ 6.39	$ 5.26
Transportation [6]	**0.55**	0.55	0.50
Realized price, net of transportation	**3.72**	5.84	4.76
Royalties [3]	**0.28**	0.51	0.42
Production expense [4]	**1.47**	1.25	1.31
Netback [2]	**$ 1.97**	$ 4.08	$ 3.03
Barrels of oil equivalent ($/BOE) [1]			
Realized price [2]	**$ 44.98**	$ 56.83	$ 69.66
Transportation [2]	**4.03**	3.80	3.72
Realized price, net of transportation [2]	**40.95**	53.03	65.94
Royalties [3]	**6.56**	9.31	11.88
Production expense [4]	**13.51**	15.17	12.70
Netback [2]	**$ 20.88**	$ 28.55	$ 41.36

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as royalties divided by respective sales volumes.

(4) Calculated as production expense divided by respective sales volumes.

(5) Calculated as natural gas sales divided by natural gas sales volumes.

(6) Calculated as natural gas transportation expense divided by natural gas sales volumes.

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs ($/bbl) (1)			
North America (2)	**$ 57.99**	$ 65.79	$ 91.44
International average (3)	**$ 98.60**	$ 118.44	$ 128.35
North Sea (3)	**$ —**	$ 118.91	$ 125.20
Offshore Africa (3)	**$ 98.60**	$ 117.74	$ 130.25
Crude oil and NGLs average (2)	**$ 58.85**	$ 69.34	$ 93.54
Natural gas ($/Mcf) (1) (3)			
North America	**$ 4.22**	$ 6.36	$ 5.20
International average	**$ 13.76**	$ 13.70	$ 11.32
North Sea	**$ 11.81**	$ 13.51	$ 20.68
Offshore Africa	**$ 14.28**	$ 13.80	$ 9.57
Natural gas average	**$ 4.27**	$ 6.39	$ 5.26
Average ($/BOE) (1) (2)	**$ 44.98**	$ 56.83	$ 69.66

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Calculated as crude oil and NGLs sales and natural gas sales divided by respective sales volumes.

North America

North America realized crude oil and NGLs prices decreased 37% to average $57.99 per bbl for the first quarter of 2023 from $91.44 per bbl for the first quarter of 2022, and decreased 12% from $65.79 per bbl for the fourth quarter of 2022. The decrease in realized crude oil and NGLs prices for the first quarter of 2023 from the comparable periods was primarily due to lower WTI benchmark pricing and fluctuations in the WCS differential. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2023 contributed approximately 217,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 19% to average $4.22 per Mcf for the first quarter of 2023 from $5.20 per Mcf for the first quarter of 2022, and decreased 34% from $6.36 per Mcf for the fourth quarter of 2022. The decrease in realized natural gas prices for the first quarter of 2023 from the comparable periods primarily reflected decreased AECO benchmark and export pricing in 2023.

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

	Three Months Ended		
(Quarterly average)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Wellhead Price (1)			
Light and medium crude oil and NGLs ($/bbl)	**$ 73.26**	$ 77.08	$ 88.63
Pelican Lake heavy crude oil ($/bbl)	**$ 67.57**	$ 73.25	$ 97.73
Primary heavy crude oil ($/bbl)	**$ 60.31**	$ 69.20	$ 97.21
Bitumen (thermal oil) ($/bbl)	**$ 48.60**	$ 58.13	$ 89.93
Natural gas ($/Mcf)	**$ 4.22**	$ 6.36	$ 5.20

(1) Amounts expressed on a per unit basis are based on sales volumes of the respective product type.

International

International realized crude oil and NGLs prices decreased 23% to average $98.60 per bbl for the first quarter of 2023 from $128.35 per bbl for the first quarter of 2022 and decreased 17% from $118.44 per bbl for the fourth quarter of 2022. Realized crude oil and NGLs prices per bbl 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 and NGLs prices for the first quarter of 2023 from the comparable periods reflected prevailing Brent benchmark pricing at the time of liftings, together with the impact of movements in the Canadian dollar.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs ($/bbl) [1]			
North America	**$ 10.10**	$ 14.07	$ 18.64
International average	**$ 9.46**	$ 6.56	$ 3.93
North Sea	**$ —**	$ 0.18	$ 0.41
Offshore Africa	**$ 9.46**	$ 16.02	$ 6.06
Crude oil and NGLs average	**$ 10.09**	$ 13.56	$ 17.80
Natural gas ($/Mcf) [1]			
North America	**$ 0.27**	$ 0.51	$ 0.41
Offshore Africa	**$ 0.69**	$ 0.71	$ 0.98
Natural gas average	**$ 0.28**	$ 0.51	$ 0.42
Average ($/BOE) [1]	**$ 6.56**	$ 9.31	$ 11.88

(1) Calculated as royalties divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

North America

North America crude oil and NGLs and natural gas royalties for the first quarter of 2023 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates [1] averaged approximately 17% of product sales for the first quarter of 2023 compared with 20% for the first quarter of 2022, and 21% for the fourth quarter of 2022. The decrease in royalty rates for the first quarter of 2023 from the comparable periods was primarily due to lower benchmark prices.

Natural gas royalty rates averaged approximately 6% of product sales for the first quarter of 2023 compared with 8% for the first quarter of 2022, and 8% for the fourth quarter of 2022. The decrease in royalty rates for the first quarter of 2023 from the comparable periods was primarily due to lower benchmark prices.

Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 9% for the first quarter of 2023 compared with 5% of product sales for the first quarter of 2022 and 13% for the fourth quarter of 2022. Royalty rates as a percentage of product sales reflected the timing of liftings and the status of payout in the various fields.

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2023	Dec 31 2022	Mar 31 2022
Crude oil and NGLs ($/bbl) (1)			
North America	**$ 16.82**	$ 16.80	$ 14.79
International average	**$ 21.90**	$ 69.70	$ 32.58
North Sea	**$ —**	$ 100.30	$ 64.24
Offshore Africa	**$ 21.90**	$ 24.30	$ 13.38
Crude oil and NGLs average	**$ 16.93**	$ 20.37	$ 15.80
Natural gas ($/Mcf) (1)			
North America	**$ 1.43**	$ 1.22	$ 1.28
International average	**$ 8.08**	$ 8.07	$ 4.61
North Sea	**$ 10.80**	$ 10.38	$ 8.21
Offshore Africa	**$ 7.35**	$ 6.98	$ 3.93
Natural gas average	**$ 1.47**	$ 1.25	$ 1.31
Average ($/BOE) (1)	**$ 13.51**	$ 15.17	$ 12.70

(1) Calculated as production expense divided by respective sales volumes. For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.

North America

North America crude oil and NGLs production expense for the first quarter of 2023 of $16.82 per bbl increased 14% from $14.79 per bbl for the first quarter of 2022, and was comparable with $16.80 per bbl for the fourth quarter of 2022. The increase in crude oil and NGLs production expense per bbl from the first quarter of 2022 was primarily due to increased power and service costs.

North America natural gas production expense for the first quarter of 2023 of $1.43 per Mcf increased 12% from $1.28 per Mcf for the first quarter of 2022, and increased 17% from $1.22 per Mcf for the fourth quarter of 2022. The increase in natural gas production expense per Mcf for the first quarter of 2023 from the comparable periods primarily reflected increased service costs. The increase from the fourth quarter of 2022 also reflected the impact of seasonal weather conditions.

International

International crude oil and NGLs production expense for the first quarter of 2023 of $21.90 per bbl decreased 33% from $32.58 per bbl for the first quarter of 2022, and decreased 69% from $69.70 per bbl for the fourth quarter of 2022. The decrease in crude oil and NGLs production expense per bbl from the comparable periods primarily reflected the timing of liftings from various fields that have different cost structures, and fluctuations in the Canadian dollar. During the first quarter of 2023, there were no crude oil liftings from the Company's platforms in the North Sea.

DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2023**	 Dec 31 2022	 Mar 31 2022
North America	**$ 890**	$ 949	$ 878
North Sea	**1**	1,653	29
Offshore Africa	**35**	41	51
Depletion, depreciation and amortization	**$ 926**	$ 2,643	$ 958
Less: Recoverability charge (1)	**—**	1,620	—
Adjusted depletion, depreciation and amortization (2)	**$ 926**	$ 1,023	$ 958
$/BOE (3)	**$ 12.14**	$ 12.78	$ 12.40

(1) Prevailing regulatory and economic conditions in 2022 and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked associated crude oil reserves as at December 31, 2022, and is accelerating abandonment. As a result, the Company completed a recoverability assessment of its assets in the North Sea, and recognized a recoverability charge of $1,620 million in depletion, depreciation and amortization.

(2) This is a non-GAAP measure used to calculate depletion, depreciation and amortization, excluding the impact of non-recurring charges that do not reflect the Company's normal course depletion, depreciation and amortization costs. It may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the financial statements (depletion, depreciation and amortization expense), as applicable, as an indication of the Company's performance. It is calculated as depletion, depreciation and amortization expense, less the impact of non-recurring charges.

(3) Non-GAAP ratio calculated as adjusted depletion, depreciation and amortization divided by sales volumes. For sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

Adjusted depletion, depreciation and amortization expense for the first quarter of 2023 of $12.14 per BOE was comparable with $12.40 per BOE for the first quarter of 2022, and decreased 5% from $12.78 per BOE for the fourth quarter of 2022. The decrease in adjusted depletion, depreciation and amortization expense per BOE for the first quarter of 2023 from the fourth quarter of 2022 reflected lower depletion rates, primarily due to increases to the Company's North America Exploration and Production reserve estimates at December 31, 2022.

Adjusted depletion, depreciation and amortization expense on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

($ millions, except per BOE amounts)	Three Months Ended **Mar 31 2023**	 Dec 31 2022	 Mar 31 2022
North America	**$ 59**	$ 51	$ 35
North Sea	**11**	10	7
Offshore Africa	**2**	2	2
Asset retirement obligation accretion	**$ 72**	$ 63	$ 44
$/BOE (1)	**$ 0.94**	$ 0.78	$ 0.56

(1) Calculated as asset retirement obligation accretion divided by sales volumes. For sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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 on an absolute and per BOE basis also reflects the impact of the timing of liftings from each field in the North Sea and Offshore Africa.

Asset retirement obligation accretion expense for the first quarter of 2023 of $0.94 per BOE increased 68% from $0.56 per BOE for the first quarter of 2022, and increased 21% from $0.78 per BOE for the fourth quarter of 2022. The increase in asset retirement obligation accretion expense for the first quarter of 2023 from the comparable periods on a per BOE basis primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during 2022.

OPERATING HIGHLIGHTS – OIL SANDS MINING AND UPGRADING

The Company continues to focus on safe, reliable, and efficient operations leveraging its technical expertise across the Horizon and AOSP sites. SCO production in the first quarter of 2023 averaged 458,228 bbl/d, primarily reflecting the reinstatement of production volumes following unplanned outages in the fourth quarter of 2022 and the completion of related mining equipment repairs in January 2023.

The Company incurred production expense of $1,042 million for the first quarter of 2023, an increase of 7% from $977 million for the first quarter of 2022, and comparable with $1,017 million for the fourth quarter of 2022. The increase in production expense in the first quarter of 2023 from the first quarter of 2022 primarily reflected higher mining service costs, partially offset by lower energy costs.

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

	Three Months Ended		
($/bbl)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Realized SCO sales price (1)	**$ 96.07**	$ 103.79	$ 112.05
Bitumen value for royalty purposes (2)	**$ 47.73**	$ 58.24	$ 85.75
Bitumen royalties (3)	**$ 10.04**	$ 14.48	$ 13.51
Transportation (1)	**$ 1.52**	$ 1.80	$ 1.55

(1) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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

(3) Calculated as royalties divided by sales volumes.

The realized SCO sales price averaged $96.07 per bbl for the first quarter of 2023, a decrease of 14% from $112.05 per bbl for the first quarter of 2022, and a decrease of 7% from $103.79 per bbl for the fourth quarter of 2022. The decrease in the realized SCO sales price for the first quarter of 2023 from the comparable periods primarily reflected the decrease in WTI benchmark pricing.

The decrease in bitumen royalties per bbl for the first quarter of 2023 from the comparable periods primarily reflected the impact of lower prevailing bitumen pricing.

Transportation expense averaged $1.52 per bbl for the first quarter of 2023, comparable with $1.55 per bbl for the first quarter of 2022, and decreased 16% from $1.80 per bbl for the fourth quarter of 2022. The decrease in transportation expense per bbl for the first quarter of 2023 from the fourth quarter of 2022 primarily reflected the impact of lower sales to the US Gulf Coast, combined with higher overall sales volumes.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production expense disclosed in note 17 to the financial statements.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Production expense, excluding natural gas costs	**$ 971**	$ 933	$ 896
Natural gas costs	**71**	84	81
Production expense	**$ 1,042**	$ 1,017	$ 977

($/bbl)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Production expense, excluding natural gas costs [1]	**$ 23.35**	$ 23.37	$ 22.57
Natural gas costs [2]	**1.71**	2.11	2.03
Production expense [3]	**$ 25.06**	$ 25.48	$ 24.60
Sales volumes (bbl/d)	**462,021**	433,731	441,324

(1) Calculated as production expense, excluding natural gas costs divided by sales volumes.

(2) Calculated as natural gas costs divided by sales volumes.

(3) Calculated as production expense divided by sales volumes.

Production expense for the first quarter of 2023 averaged $25.06 per bbl, which was comparable with $24.60 per bbl for the first quarter of 2022, and $25.48 per bbl for the fourth quarter of 2022.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Depletion, depreciation and amortization	**$ 488**	$ 481	$ 445
$/bbl [1]	**$ 11.74**	$ 12.07	$ 11.20

(1) Calculated as depletion, depreciation and amortization divided by sales volumes.

Depletion, depreciation and amortization expense for the first quarter of 2023 of $11.74 per bbl increased 5% from $11.20 per bbl for the first quarter of 2022, and decreased 3% from $12.07 per bbl for the fourth quarter of 2022. The increase in depletion, depreciation and amortization on a per bbl basis for the first quarter of 2023 from the first quarter of 2022 primarily reflected the impact of equipment lease additions in the first quarter of 2023. The decrease on a per bbl basis for the first quarter of 2023 compared to the fourth quarter of 2022 primarily reflected the impact of higher sales volumes.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

($ millions, except per bbl amounts)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Asset retirement obligation accretion	**$ 20**	$ 19	$ 15
$/bbl [1]	**$ 0.47**	$ 0.49	$ 0.39

(1) Calculated as asset retirement obligation accretion divided by sales volumes.

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

Asset retirement obligation accretion expense of $0.47 per bbl for the first quarter of 2023 increased 21% from $0.39 per bbl for the first quarter of 2022, and decreased 4% from $0.49 per bbl for the fourth quarter of 2022. The increase on a per bbl basis from the first quarter of 2022 primarily reflected the impact of cost estimate and discount rate revisions made to the asset retirement obligation during 2022, while the decrease from the fourth quarter of 2022 primarily reflected the impact of higher sales volumes.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Product sales			
Midstream activities	**$ 21**	$ 21	$ 20
NWRP, refined product sales and other	**250**	205	249
Segmented revenue	**271**	226	269
Less:			
NWRP, refining toll	**70**	57	61
Midstream activities	**8**	6	5
Production expense	**78**	63	66
NWRP, transportation and feedstock costs	**153**	155	179
Depreciation	**4**	5	4
Segmented earnings	**$ 36**	$ 3	$ 20

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 bbl/d bitumen upgrader and refinery that processes approximately 12,500 bbl/d (25% toll payer) of bitumen feedstock for the Company and 37,500 bbl/d (75% toll payer) of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC"), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the first quarter of 2023, production of ultra-low sulphur diesel and other refined products averaged 85,376 BOE/d (21,344 BOE/d to the Company) (three months ended March 31, 2022 – 71,975 BOE/d; 17,994 BOE/d to the Company) reflecting the 25% toll payer commitment.

As at March 31, 2023, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $567 million (December 31, 2022 – $551 million). For the three months ended March 31, 2023, the unrecognized share of the equity loss was $16 million (three months ended March 31, 2022 – unrecognized equity loss of $10 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Administration expense	**$ 106**	$ 108	$ 116
$/BOE (1)	**$ 0.90**	$ 0.90	$ 0.99
Sales volumes (BOE/d) (2)	**1,309,942**	1,303,996	1,300,300

(1) Calculated as administration expense divided by sales volumes.

(2) Total Company sales volumes.

Administration expense for the first quarter of 2023 of $0.90 per BOE decreased 9% from $0.99 per BOE for the first quarter of 2022, and was comparable with $0.90 per BOE for the fourth quarter of 2022. The decrease in administration expense per BOE for the first quarter of 2023 from the first quarter of 2022 was primarily due to higher overhead recoveries.

SHARE-BASED COMPENSATION

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Share-based compensation expense	**$ 66**	$ 319	$ 534

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 Performance Share Unit ("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 $66 million share-based compensation expense for the three months ended March 31, 2023, 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.

INTEREST AND OTHER FINANCING EXPENSE

	Three Months Ended		
($ millions, except effective interest rate)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Interest and other financing expense	**$ 154**	$ 76	$ 163
Less: Interest income and other (1)	**(9)**	(93)	(4)
Interest expense on long-term debt and lease liabilities (1)	**$ 163**	$ 169	$ 167
Average current and long-term debt (2)	**$ 12,343**	$ 13,174	$ 14,950
Average lease liabilities (2)	**1,516**	1,508	1,551
Average long-term debt and lease liabilities (2)	**$ 13,859**	$ 14,682	$ 16,501
Average effective interest rate (3) (4)	**4.6%**	4.5%	4.0%
Interest and other financing expense per $/BOE (5)	**$ 1.30**	$ 0.63	$ 1.40
Sales volumes (BOE/d) (6)	**1,309,942**	1,303,996	1,300,300

(1) Item is a component of interest and other financing expense.

(2) The average of current and long-term debt and lease liabilities outstanding during the respective period.

(3) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(4) Calculated as the average interest on long-term debt and lease liabilities divided by the average long-term debt and lease liabilities balance. The Company presents its average effective interest rate for financial statement users to evaluate the Company’s average cost of debt borrowings.

(5) Calculated as interest and other financing expense divided by sales volumes.

(6) Total Company sales volumes.

Interest and other financing expense per BOE for the first quarter of 2023 decreased $0.10 per BOE to $1.30 per BOE from $1.40 per BOE for the first quarter of 2022, and increased $0.67 per BOE from $0.63 per BOE for the fourth quarter of 2022. The decrease in interest and other financing expense per BOE for the first quarter of 2023 from the first quarter of 2022 was primarily due to lower debt levels. The increase in the first quarter of 2023 from the fourth quarter of 2022 reflected the impact of accrued interest on the deferred PRT recovery in the fourth quarter of 2022.

The Company's average effective interest rate for the first quarter of 2023 increased from the first quarter of 2022 primarily due to higher benchmark interest rates on commercial paper drawn during the first quarter of 2023 and the repayment of medium-term notes during 2022.

RISK MANAGEMENT ACTIVITIES

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

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Foreign currency contracts	**$ (2)**	$ 3	$ 22
Natural gas financial instruments (1)	**3**	(6)	5
Crude oil and NGLs financial instruments (1)	**—**	1	5
Net realized loss (gain)	**1**	(2)	32
Foreign currency contracts	**3**	(2)	(13)
Natural gas financial instruments (1)	**17**	18	32
Crude oil and NGLs financial instruments (1)	**—**	(1)	7
Net unrealized loss	**20**	15	26
Net loss	**$ 21**	$ 13	$ 58

(1) Commodity financial instruments were assumed in the acquisition of Storm Resources Ltd. and Painted Pony Energy Ltd. in the fourth quarter of 2021 and 2020, respectively.

During the first quarter of 2023, net realized risk management losses were related to the settlement of natural gas financial instruments, partially offset by gains on foreign currency contracts. The Company recorded a net unrealized loss of $20 million ($16 million after-tax of $4 million) on its risk management activities for the three months ended March 31, 2023 (three months ended December 31, 2022 – unrealized loss of $15 million, $11 million after-tax of $4 million; three months ended March 31, 2022 – unrealized loss of $26 million, $17 million after-tax of $9 million).

Further details related to outstanding derivative financial instruments at March 31, 2023 are disclosed in note 15 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Net realized (gain) loss	**$ (11)**	$ 18	$ 10
Net unrealized gain	**(3)**	(203)	(156)
Net gain (1)	**$ (14)**	$ (185)	$ (146)

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

The net realized foreign exchange gain for the first quarter of 2023 was primarily due to foreign exchange rate fluctuations on settlement of working capital items denominated in US dollars or UK pounds sterling. The net unrealized foreign exchange gain for the first quarter of 2023 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate at March 31, 2023 was US$0.7392 (December 31, 2022 – US$0.7389, March 31, 2022 – US$0.8010).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
North America [1]	**$ 480**	$ 345	$ 834
North Sea	**6**	33	7
Offshore Africa	**10**	23	12
PRT – North Sea	**(40)**	(5)	(7)
Other taxes	**3**	3	5
Current income tax	**459**	399	851
Deferred corporate income tax	**23**	(148)	125
Deferred PRT – North Sea	**7**	(441)	—
Deferred income tax	**30**	(589)	125
Income tax	**$ 489**	$ (190)	$ 976
Earnings before taxes	**$ 2,288**	$ 1,330	$ 4,077
Effective tax rate on net earnings [2]	**21%**	(14)%	24%

($ millions, except effective tax rates)	Three Months Ended Mar 31 2023	Dec 31 2022	Mar 31 2022
Income tax	**$ 489**	$ (190)	$ 976
Tax effect on non-operating items [3]	**8**	980	8
Current PRT - North Sea	**40**	5	7
Other taxes	**(3)**	(3)	(5)
Effective tax on adjusted net earnings	**$ 534**	$ 792	$ 986
Adjusted net earnings from operations [4]	**$ 1,881**	$ 2,194	$ 3,376
Adjusted net earnings from operations, before taxes	**$ 2,415**	$ 2,986	$ 4,362
Effective tax rate on adjusted net earnings from operations [5] [6]	**22%**	27%	23%

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

(2) Calculated as total of current and deferred income tax divided by earnings before taxes.

(3) Includes the net tax effect of PSUs, unrealized risk management, abandonment expenditure recovery, and the recoverability charge recognized in the fourth quarter of 2022 in adjusted net earnings from operations.

(4) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(5) This is a non-GAAP ratio and may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance.

(6) Calculated as effective tax on adjusted net earnings divided by adjusted net earnings from operations, before taxes. The Company presents its effective tax rate on adjusted net earnings from operations for financial statement users to evaluate the Company's effective tax rate on its core business activities.

The effective tax rate on net earnings and adjusted net earnings from operations for the first quarter of 2023 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.

The current corporate income tax and PRT in the North Sea for the first quarter of 2023 and the comparable periods included the impact of carrybacks of abandonment expenditures related to decommissioning activities at the Company's platforms in the North Sea. Deferred PRT and income taxes for the three months ended December 31, 2022 also reflected the impact of the recoverability charge recognized in depletion, depreciation and amortization during the period related to 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) (2)

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Exploration and Evaluation			
Net expenditures	**$ 28**	$ 11	$ 22
Net property dispositions	**—**	(2)	(3)
Total Exploration and Evaluation	**28**	9	19
Property, Plant and Equipment			
Net property acquisitions	**—**	—	482
Well drilling, completion and equipping	**510**	407	344
Production and related facilities	**361**	351	211
Other	**11**	15	13
Total Property, Plant and Equipment	**882**	773	1,050
Total Exploration and Production	**910**	782	1,069
Oil Sands Mining and Upgrading			
Project costs	**52**	98	45
Sustaining capital	**261**	367	206
Turnaround costs	**22**	16	60
Net property dispositions	**—**	(40)	—
Other	**1**	1	1
Total Oil Sands Mining and Upgrading	**336**	442	312
Midstream and Refining	**3**	2	2
Head office	**8**	7	5
Abandonments expenditures, net (2)	**137**	84	67
Net capital expenditures	**$ 1,394**	$ 1,317	$ 1,455
By Segment			
North America	**$ 884**	$ 677	$ 1,045
North Sea	**3**	48	11
Offshore Africa	**23**	57	13
Oil Sands Mining and Upgrading	**336**	442	312
Midstream and Refining	**3**	2	2
Head office	**8**	7	5
Abandonments expenditures, net (2)	**137**	84	67
Net capital expenditures	**$ 1,394**	$ 1,317	$ 1,455

(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) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

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

Net capital expenditures for the first quarter of 2023 included base capital expenditures [1] of $1,117 million and strategic growth capital expenditures [1] of $277 million, in accordance with the Company's capital budget.

2023 Capital Budget

On November 30, 2022, the Company announced its 2023 base capital budget [2] targeted at approximately $4,190 million. The budget also includes incremental strategic growth capital of approximately $1,020 million that targets to add additional production and capacity growth beyond 2023 in the Company's Exploration and Production segments, and long life low decline thermal in situ and Oil Sands Mining and Upgrading assets.

The 2023 capital budget constitutes forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Drilling Activity [1] [2]

	Three Months Ended		
(number of net wells)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Net successful crude oil wells [3]	**83**	80	56
Net successful natural gas wells	**21**	15	23
Dry wells	**2**	—	—
Total	**106**	95	79
Success rate	**98%**	100%	100%

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

(2) In the first quarter of 2023, on a net basis, the Company drilled 334 stratigraphic wells and 7 service wells in the Oil Sands Mining and Upgrading segment, as well as 24 stratigraphic and 27 service wells in the Company's thermal oil projects, and 2 service wells in the Northern Plains region.

(3) Includes bitumen wells.

North America

During the first quarter of 2023, the Company drilled 21 net natural gas wells, 42 net primary heavy crude oil wells, 2 net Pelican Lake heavy crude oil wells, 25 net bitumen (thermal oil) wells, and 16 net light crude oil wells.

(1) Item is a component of net capital expenditures. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on net capital expenditures.

(2) Forward looking non-GAAP Financial Measure. The capital budget is based on net capital expenditures (Non-GAAP Financial Measure) and excludes net acquisition costs. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A for more details on net capital expenditures.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)		**Mar 31 2023**		Dec 31 2022		Mar 31 2022
Adjusted working capital (1)	**$**	**(307)**	$	(1,190)	$	281
Long-term debt, net (2)	**$**	**11,932**	$	10,525	$	13,782
Shareholders' equity	**$**	**38,585**	$	38,175	$	38,490
Debt to book capitalization (2)		**23.6%**		21.6%		26.4%
After-tax return on average capital employed (3)		**19.7%**		22.1%		18.9%

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

(2) Capital Management Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

As at March 31, 2023, 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, 2022. 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 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:
  - Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers' acceptances, LIBOR, SOFR, 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.
  - In July 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. 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.
  - In July 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. 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 March 31, 2023, the Company had undrawn revolving bank credit facilities of $5,520 million. Including cash and cash equivalents and short-term investments, the Company had approximately $6,096 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2023, the Company had $588 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

Long-term debt, net was $11,932 million at March 31, 2023, resulting in a debt to book capitalization ratio (1) of 23.6% (December 31, 2022 – 21.6%), which was below 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 also 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 as at March 31, 2023 are discussed in note 8 to the financial statements.

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2023, 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 as at March 31, 2023 are discussed in note 15 to the financial statements.

As at March 31, 2023, the maturity dates of certain financial liabilities, including 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)	$ 992	$ 1,809	$ 3,168	$ 6,121
Other long-term liabilities (2)	$ 253	$ 158	$ 413	$ 720
Interest and other financing expense (3)	$ 629	$ 589	$ 1,400	$ 3,664

(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, $244 million; one to less than two years, $158 million; two to less than five years, $413 million; and thereafter, $720 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at March 31, 2023.

Share Capital

As at March 31, 2023, there were 1,097,390,000 common shares outstanding (December 31, 2022 – 1,102,636,000 common shares) and 32,633,000 stock options outstanding (December 31, 2022 - 31,150,000). As at May 2, 2023, the Company had 1,096,088,000 common shares outstanding and 31,532,000 stock options outstanding.

On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share, beginning with the dividend paid on April 5, 2023. On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 8, 2023, 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 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the three months ended March 31, 2023, the Company purchased 8,900,000 common shares at a weighted average price of $76.96 per common share for a total cost of $685 million. Retained earnings were reduced by $601 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2023, the Company purchased 2,100,000 common shares at a weighted average price of $80.60 per common share for a total cost of $169 million.

(1) Capital management measure. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2023:

($ millions)	Remaining 2023	2024	2025	2026	2027	Thereafter
Product transportation and processing (1)	$ 892	$ 1,387	$ 1,238	$ 1,147	$ 1,096	$ 11,273
North West Redwater Partnership service toll (2)	$ 114	$ 154	$ 153	$ 135	$ 120	$ 4,952
Offshore vessels and equipment	$ 31	$ 35	$ —	$ —	$ —	$ —
Field equipment and power	$ 30	$ 28	$ 26	$ 23	$ 22	$ 215
Other	$ 18	$ 24	$ 22	$ 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 $2,913 million of interest payable over the 40-year tolling period, ending in 2058.

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. 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, 2022.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2023 that have materially affected, or are reasonably likely to materially affect the Company’s internal control over financial reporting. 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.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies, and should not be considered an alternative to or more meaningful than the most directly comparable financial measure presented in the financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this MD&A, and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below.

Adjusted Net Earnings from Operations

Adjusted net earnings from operations is a non-GAAP financial measure that adjusts net earnings as presented in the Company's consolidated Statements of Earnings, for non-operating items, net of tax. The Company considers adjusted net earnings 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. A reconciliation for adjusted net earnings from operations is presented below.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Net earnings	**$ 1,799**	$ 1,520	$ 3,101
Share-based compensation, net of tax (1)	**62**	309	526
Unrealized risk management loss, net of tax (2)	**16**	11	17
Unrealized foreign exchange gain, net of tax (3)	**(3)**	(203)	(156)
Realized foreign exchange loss on debt settlement, net of tax	**—**	7	—
Loss (gain) from investments, net of tax (4)	**7**	(88)	(83)
Recoverability charge, net of tax (5)	**—**	651	—
Other, net of tax (6)	**—**	(13)	(29)
Non-operating items, net of tax	**82**	674	275
Adjusted net earnings from operations	**$ 1,881**	$ 2,194	$ 3,376

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and 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. Pre-tax share-based compensation for the three months ended March 31, 2023 was an expense of $66 million (three months ended December 31, 2022 – $319 million expense, three months ended March 31, 2022 – $534 million expense).

(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. The amounts ultimately realized may be materially different than those amounts reflected in the financial statements due to changes in prices of the underlying items hedged, primarily crude oil, natural gas and foreign exchange. Pre-tax unrealized risk management loss for the three months ended March 31, 2023 was $20 million (three months ended December 31, 2022 – $15 million loss, three months ended March 31, 2022 – $26 million loss).

(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. Pre- and after-tax amounts for these unrealized foreign exchange losses and gains are the same.

(4) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with losses and gains recognized in net earnings. There is zero net tax impact on these losses and gains from investments.

(5) The Company recognized a recoverability charge of $1,620 million in depletion, depreciation and amortization at December 31, 2022 relating to the de-booking of reserves at the Ninian field in the North Sea. Prevailing regulatory and economic conditions in 2022 and the increasingly challenging commercial outlook in the United Kingdom, including the impact of higher natural gas and carbon costs, led the Company to assess the viability of its North Sea operations. Following a detailed review of its development plans, the Company determined that the Ninian field is no longer economic, de-booked associated reserves as at December 31, 2022 and is accelerating abandonment.

(6) Other relates to the impact of government grant income under the provincial well-site rehabilitation programs. Pre-tax other for the three months ended March 31, 2023 was $nil (three months ended December 31, 2022 – $16 million, three months ended March 31, 2022 – $38 million).

Adjusted Funds Flow

Adjusted funds flow is a non-GAAP financial measure that represents cash flows from operating activities as presented in the Company's consolidated Statements of Cash Flows, adjusted for the net change in non-cash working capital, abandonment expenditures excluding the impact of government grant income under the provincial well-site rehabilitation programs, and movements in other long-term assets. 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. A reconciliation for adjusted funds flow, from cash flows from operating activities is presented below.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Cash flows from operating activities	**$ 1,295**	$ 4,544	$ 2,853
Net change in non-cash working capital	**1,908**	(517)	1,940
Abandonment expenditures, net [(1)]	**137**	84	67
Movements in other long-term assets [(2)]	**89**	65	115
Adjusted funds flow	**$ 3,429**	$ 4,176	$ 4,975

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section below.

(2) Includes the unamortized cost of the share bonus program.

Adjusted Net Earnings from Operations and Adjusted Funds Flow, Per Share (Basic and Diluted)

Adjusted net earnings from operations and adjusted funds flow, per common share (basic and diluted), are non-GAAP ratios that represent those non-GAAP measures divided by the weighted average number of basic and diluted common shares outstanding for the period, respectively, as presented in note 14 to the financial statements. These non-GAAP measures, disclosed on a per share basis, enable a comparison to the per share amounts disclosed in the Company's financial statements prepared in accordance with IFRS.

Abandonment Expenditures, net

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's annual capital budget. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's consolidated Statements of Cash Flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. A reconciliation of abandonment expenditures, net is presented below.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Abandonment expenditures	**$ 137**	$ 100	$ 105
Government grants for abandonment expenditures	**—**	(16)	(38)
Abandonment expenditures, net	**$ 137**	$ 84	$ 67

Netback

Netback is a non-GAAP ratio that represents net cash flows provided from core activities after the impact of all costs associated with bringing a product to market on a per unit basis. The Company considers netback a key measure in evaluating its performance as it demonstrates the efficiency and profitability of the Company's activities. Refer to the "Operating Highlights – Exploration and Production" section of this MD&A for the netback calculations on a per unit basis for crude oil and NGLs, natural gas and on a total barrels of oil equivalent basis.

The netback calculations include the non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 17 to the financial statements.

Realized Price ($/bbl and $/BOE) – Exploration and Production

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales include the impact of blending costs and other by-product sales. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

Reconciliations for Exploration and Production realized crude oil and NGLs sales and BOE sales and the calculations for realized price are presented below.

	Three Months Ended		
($ millions, except bbl/d and $/bbl)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Crude oil and NGLs (bbl/d)			
North America	**481,045**	482,931	494,810
International			
North Sea	**—**	20,854	11,245
Offshore Africa	**10,393**	14,059	18,550
Total International	**10,393**	34,913	29,795
Total sales volumes	**491,438**	517,844	524,605
Crude oil and NGLs sales (1)	**$ 3,841**	$ 4,505	$ 5,883
Less: Blending and feedstock costs (2)	**1,238**	1,202	1,466
Realized crude oil and NGLs sales	**$ 2,603**	$ 3,303	$ 4,417
Realized price ($/bbl)	**$ 58.85**	$ 69.34	$ 93.54

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

	Three Months Ended		
($ millions, except BOE/d and $/BOE)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Barrels of oil equivalent (BOE/d)			
North America	**835,542**	833,719	826,161
International			
North Sea	**419**	21,375	11,720
Offshore Africa	**11,961**	15,171	21,095
Total International	**12,380**	36,546	32,815
Total sales volumes	**847,922**	870,265	858,976
Barrels of oil equivalent sales (1)	**$ 4,663**	$ 5,751	$ 6,832
Less: Blending and feedstock costs (2)	**1,238**	1,202	1,466
Less: Sulphur income	**(8)**	(3)	(19)
Realized barrels of oil equivalent sales	**$ 3,433**	$ 4,552	$ 5,385
Realized price ($/BOE)	**$ 44.98**	$ 56.83	$ 69.66

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 17 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled below in the "Transportation – Exploration and Production" section.

Transportation – Exploration and Production

Transportation ($/BOE, $/bbl and $/Mcf) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by the respective sales volumes. The Company calculates transportation to demonstrate its cost to deliver products to the market excluding the impact of blending costs. A reconciliation for Exploration and Production transportation and the calculations for transportation on a per unit basis are presented below.

	Three Months Ended		
($ millions, except $ per unit amounts)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Transportation, blending and feedstock (1)	**$ 1,546**	$ 1,506	$ 1,754
Less: Blending and feedstock costs	**1,238**	1,202	1,466
Transportation	**$ 308**	$ 304	$ 288
Transportation ($/BOE)	**$ 4.03**	$ 3.80	$ 3.72
Amounts attributed to crude oil and NGLs	**$ 200**	$ 196	$ 197
Transportation ($/bbl)	**$ 4.52**	$ 4.11	$ 4.18
Amounts attributed to natural gas	**$ 108**	$ 108	$ 91
Transportation ($/Mcf)	**$ 0.55**	$ 0.55	$ 0.50

(1) Transportation, blending and feedstock in note 17 to the financial statements.

North America – Realized Product Prices and Royalties

Realized crude oil and NGLs price ($/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales include the impact of blending costs. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

Crude oil and NGLs royalty rate is a non-GAAP ratio that is calculated as crude oil and NGLs royalties divided by realized crude oil and NGLs sales. The Company considers crude oil and NGLs royalty rate a key measure in evaluating its performance, as it describes the Company's royalties for crude oil and NGLs sales volumes on a per unit basis.

A reconciliation for North America realized crude oil and NGLs sales and the calculations for realized crude oil and NGLs prices and the royalty rates are presented below.

	Three Months Ended		
($ millions, except $/bbl and royalty rates)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Crude oil and NGLs sales (1)	**$ 3,749**	$ 4,124	$ 5,539
Less: Blending and feedstock costs (2)	**1,238**	1,202	1,466
Realized crude oil and NGLs sales	**$ 2,511**	$ 2,922	$ 4,073
Realized crude oil and NGLs prices ($/bbl)	**$ 57.99**	$ 65.79	$ 91.44
Crude oil and NGLs royalties (3)	**$ 437**	$ 625	$ 830
Crude oil and NGLs royalty rates	**17%**	21%	20%

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Blending and feedstock costs are a component of transportation, blending and feedstock expense as reconciled above in the "Transportation – Exploration and Production" section.

(3) Item is a component of royalties in note 17 to the financial statements.

Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) including the impact of blending and feedstock costs, divided by SCO sales volumes. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

Transportation ($/bbl) is a non-GAAP ratio calculated as transportation (a non-GAAP financial measure) divided by SCO sales volumes. The Company calculates transportation to demonstrate its cost to deliver product to the market excluding the impact of blending and feedstock costs.

Reconciliations for Oil Sands Mining and Upgrading realized SCO sales and transportation and the calculations for realized SCO sales price and transportation on a per unit basis are presented below.

	Three Months Ended		
($ millions, except for bbl/d and $/bbl)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
SCO sales volumes (bbl/d)	**462,021**	433,731	441,324
Crude oil and NGLs sales [(1)]	**$ 4,482**	$ 4,935	$ 4,851
Less: Blending and feedstock costs	**487**	795	401
Realized SCO sales	**$ 3,995**	$ 4,140	$ 4,450
Realized SCO sales price ($/bbl)	**$ 96.07**	$ 103.79	$ 112.05
Transportation, blending and feedstock [(2)]	**$ 550**	$ 867	$ 463
Less: Blending and feedstock costs	**487**	795	401
Transportation	**$ 63**	$ 72	$ 62
Transportation ($/bbl)	**$ 1.52**	$ 1.80	$ 1.55

(1) Crude oil and NGLs sales in note 17 to the financial statements.

(2) Transportation, blending and feedstock in note 17 to the financial statements.

Net Capital Expenditures

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 proceeds from investments, 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. A reconciliation of net capital expenditures is presented below.

	Three Months Ended		
($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Cash flows used in investing activities	**$ 1,153**	$ 1,262	$ 1,251
Net change in non-cash working capital	**104**	(29)	137
Capital expenditures	**1,257**	1,233	1,388
Abandonment expenditures, net [(1)]	**137**	84	67
Net capital expenditures [(2)]	**$ 1,394**	$ 1,317	$ 1,455

(1) Non-GAAP Financial Measure. A reconciliation of abandonment expenditures, net is presented in the "Abandonment Expenditures, net" section above.

(2) Includes base capital expenditures of $1,117 million and strategic growth capital expenditures of $277 million. Strategic growth capital expenditures represent the allocation of the Company's free cash flow that will be directed to strategic capital growth opportunities that target to increase production volumes in future periods and that exceed the Company's base capital expenditures for the current fiscal year, as outlined in the Company's capital budget.

Liquidity

Liquidity is a non-GAAP financial measure that represents the availability of readily available undrawn bank credit facilities, cash and cash equivalents, and other highly liquid assets to meet short-term funding requirements and to assist in assessing the Company's financial position. The Company's calculation of liquidity is presented below.

($ millions)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Undrawn bank credit facilities	**$ 5,520**	$ 5,520	$ 5,590
Cash and cash equivalents	**92**	920	125
Investments	**484**	491	392
Liquidity	**$ 6,096**	$ 6,931	$ 6,107

Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt less cash and cash equivalents, as disclosed in note 13 to the financial statements.

Debt to Book Capitalization

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 13 to the financial statements.

After-Tax Return on Average Capital Employed

After-tax return on average capital employed as defined by the Company is a non-GAAP ratio. The ratio is calculated as net earnings 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. The Company considers this ratio a key measure in evaluating the Company's ability to generate profit and the efficiency with which it employs capital. A reconciliation of the Company's after-tax return on average capital employed is presented below.

($ millions, except ratios)	**Mar 31 2023**	Dec 31 2022	Mar 31 2022
Interest adjusted after-tax return:			
Net earnings, 12 months trailing	**$ 9,635**	$ 10,937	$ 9,388
Interest and other financing expense, net of tax, 12 months trailing (1)	**417**	424	531
Interest adjusted after-tax return	**$ 10,052**	$ 11,361	$ 9,919
12 months average current portion long-term debt (2)	**$ 1,357**	$ 1,359	$ 1,762
12 months average long-term debt (2)	**11,228**	11,761	14,981
12 months average common shareholders' equity (2)	**38,544**	38,218	35,680
12 months average capital employed	**$ 51,129**	$ 51,338	$ 52,423
After-tax return on average capital employed	**19.7%**	22.1%	18.9%

(1) The blended tax rate on interest was 23% for each of the periods presented.

(2) For the purpose of this non-GAAP ratio, the measurement of average current and long-term debt and common shareholders equity are determined on a consistent basis, as an average of the opening and quarterly period end values for the 12 month trailing period for each of the periods presented.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED BALANCE SHEETS

As at (millions of Canadian dollars, unaudited)	Note	Mar 31 2023	Dec 31 2022
ASSETS			
Current assets			
Cash and cash equivalents		**$ 92**	$ 920
Accounts receivable		**3,402**	3,555
Inventory		**1,920**	1,815
Prepaids and other		**242**	215
Investments	6	**484**	491
Current portion of other long-term assets	7	**65**	61
		6,205	7,057
Exploration and evaluation assets	3	**2,244**	2,226
Property, plant and equipment	4	**64,744**	64,859
Lease assets	5	**1,439**	1,447
Other long-term assets	7	**628**	553
		$ 75,260	$ 76,142
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,220**	$ 1,341
Accrued liabilities		**3,817**	4,209
Current income taxes payable		**100**	1,324
Current portion of long-term debt	8	**992**	404
Current portion of other long-term liabilities	5,9	**1,375**	1,373
		7,504	8,651
Long-term debt	8	**11,032**	11,041
Other long-term liabilities	5,9	**7,995**	8,161
Deferred income taxes		**10,144**	10,114
		36,675	37,967
SHAREHOLDERS' EQUITY			
Share capital	11	**10,496**	10,294
Retained earnings		**27,882**	27,672
Accumulated other comprehensive income	12	**207**	209
		38,585	38,175
		$ 75,260	$ 76,142

Commitments and contingencies (note 16).

Approved by the Board of Directors on May 3, 2023.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Mar 31 2023	Mar 31 2022
Product sales	17	**$ 9,548**	$ 12,132
Less: royalties		**(918)**	(1,455)
Revenue		**8,630**	10,677
Expenses			
Production		**2,164**	2,040
Transportation, blending and feedstock		**2,334**	2,455
Depletion, depreciation and amortization	4,5	**1,418**	1,407
Administration		**106**	116
Share-based compensation	9	**66**	534
Asset retirement obligation accretion	9	**92**	59
Interest and other financing expense		**154**	163
Risk management activities	15	**21**	58
Foreign exchange gain		**(14)**	(146)
Loss (gain) from investments	6	**1**	(86)
		6,342	6,600
Earnings before taxes		**2,288**	4,077
Current income tax expense	10	**459**	851
Deferred income tax expense	10	**30**	125
Net earnings		**$ 1,799**	$ 3,101
Net earnings per common share			
Basic	14	**$ 1.63**	$ 2.66
Diluted	14	**$ 1.62**	$ 2.63

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended Mar 31 2023	Mar 31 2022
Net earnings	**$ 1,799**	$ 3,101
Items that may be reclassified subsequently to net earnings		
Net change in derivative financial instruments designated as cash flow hedges		
Unrealized income during the period, net of taxes of $nil (2022 – $1 million)	**—**	3
Reclassification to net earnings, net of taxes of $nil (2022 – $1 million)	**(1)**	(3)
	(1)	—
Foreign currency translation adjustment		
Translation of net investment	**(1)**	(37)
Other comprehensive loss, net of taxes	**(2)**	(37)
Comprehensive income	**$ 1,797**	$ 3,064

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2023**	Three Months Ended Mar 31 2022
Share capital	11		
Balance – beginning of period		**$ 10,294**	$ 10,168
Issued upon exercise of stock options		**143**	252
Previously recognized liability on stock options exercised for common shares		**143**	184
Purchase of common shares under Normal Course Issuer Bid		**(84)**	(140)
Balance – end of period		**10,496**	10,464
Retained earnings			
Balance – beginning of period		**27,672**	26,778
Net earnings		**1,799**	3,101
Dividends on common shares	11	**(988)**	(872)
Purchase of common shares under Normal Course Issuer Bid	11	**(601)**	(943)
Balance – end of period		**27,882**	28,064
Accumulated other comprehensive income (loss)	12		
Balance – beginning of period		**209**	(1)
Other comprehensive loss, net of taxes		**(2)**	(37)
Balance – end of period		**207**	(38)
Shareholders' equity		**$ 38,585**	$ 38,490

CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)	Note	Three Months Ended **Mar 31 2023**	Mar 31 2022
Operating activities			
Net earnings		**$ 1,799**	$ 3,101
Non-cash items			
Depletion, depreciation and amortization		**1,418**	1,407
Share-based compensation		**66**	534
Asset retirement obligation accretion		**92**	59
Unrealized risk management loss		**20**	26
Unrealized foreign exchange gain		**(3)**	(156)
Loss (gain) from investments	6	**7**	(83)
Deferred income tax expense		**30**	125
Other		**(89)**	(115)
Abandonment expenditures		**(137)**	(105)
Net change in non-cash working capital		**(1,908)**	(1,940)
Cash flows from operating activities		**1,295**	2,853
Financing activities			
Issue of bank credit facilities and commercial paper, net	8	**588**	348
Repayment of medium-term notes	8	**(11)**	(1,000)
Payment of lease liabilities	5,9	**(67)**	(49)
Issue of common shares on exercise of stock options	11	**143**	252
Dividends on common shares		**(938)**	(689)
Purchase of common shares under Normal Course Issuer Bid	11	**(685)**	(1,083)
Cash flows used in financing activities		**(970)**	(2,221)
Investing activities			
Net expenditures on exploration and evaluation assets	3,17	**(28)**	(19)
Net expenditures on property, plant and equipment	4,17	**(1,229)**	(1,369)
Net change in non-cash working capital		**104**	137
Cash flows used in investing activities		**(1,153)**	(1,251)
Decrease in cash and cash equivalents		**(828)**	(619)
Cash and cash equivalents – beginning of period		**920**	744
Cash and cash equivalents – end of period		**$ 92**	$ 125
Interest paid on long-term debt, net		**$ 168**	$ 184
Income taxes paid, net		**$ 1,556**	$ 1,759

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, 2022, 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, 2022.

Critical Accounting Estimates and Judgements

The Company has made estimates, assumptions and judgements regarding certain assets, liabilities, revenues and expenses in the preparation of these interim consolidated financial statements, primarily related to unsettled transactions and events as of the date of these interim consolidated financial statements. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

2. CHANGE IN ACCOUNTING POLICIES

In May 2021, the IASB issued amendments to IAS 12 "Income Taxes" to require companies to recognize deferred tax on particular transactions that, on initial recognition, give rise to equal amounts of taxable and deductible temporary differences. The amendments were adopted on January 1, 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

In February 2021, the IASB issued amendments to IAS 1 to require entities to disclose their material accounting policy information rather than their significant accounting policies. To support this amendment the IASB also amended IFRS Practice Statement 2 “Making Materiality Judgements”. The amendments were adopted on January 1, 2023 and did not have a significant impact on the Company's interim consolidated financial statements.

3. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
Cost					
At December 31, 2022	$ 2,026	$ —	$ 98	$ 102	$ 2,226
Additions	**28**	**—**	**—**	**—**	**28**
Transfers to property, plant and equipment	**(10)**	**—**	**—**	**—**	**(10)**
At March 31, 2023	**$ 2,044**	**$ —**	**$ 98**	**$ 102**	**$ 2,244**

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, 2022	$ 81,075	$ 8,258	$ 4,332	$ 47,732	$ 474	$ 536	$ 142,407
Additions/Acquisitions	**865**	**3**	**23**	**336**	**3**	**8**	**1,238**
Transfers from exploration & evaluation assets	**10**	**—**	**—**	**—**	**—**	**—**	**10**
Derecognitions [(1)]	**(208)**	**—**	**—**	**(50)**	**—**	**—**	**(258)**
Foreign exchange adjustments and other	**—**	**(3)**	**(2)**	**—**	**—**	**—**	**(5)**
At March 31, 2023	**$ 81,742**	**$ 8,258**	**$ 4,353**	**$ 48,018**	**$ 477**	**$ 544**	**$ 143,392**
Accumulated depletion and depreciation							
At December 31, 2022	$ 55,835	$ 8,106	$ 3,277	$ 9,712	$ 198	$ 420	$ 77,548
Expense	**867**	**—**	**29**	**449**	**4**	**6**	**1,355**
Derecognitions [(1)]	**(208)**	**—**	**—**	**(50)**	**—**	**—**	**(258)**
Foreign exchange adjustments and other	**(5)**	**5**	**11**	**(8)**	**—**	**—**	**3**
At March 31, 2023	**$ 56,489**	**$ 8,111**	**$ 3,317**	**$ 10,103**	**$ 202**	**$ 426**	**$ 78,648**
Net book value							
At March 31, 2023	**$ 25,253**	**$ 147**	**$ 1,036**	**$ 37,915**	**$ 275**	**$ 118**	**$ 64,744**
At December 31, 2022	$ 25,240	$ 152	$ 1,055	$ 38,020	$ 276	$ 116	$ 64,859

(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, 2022	$ 912	$ 377	$ 97	$ 61	$ 1,447
Additions	**17**	**34**	**9**	**—**	**60**
Depreciation	**(25)**	**(27)**	**(6)**	**(5)**	**(63)**
Foreign exchange adjustments and other	**—**	**—**	**(5)**	**—**	**(5)**
At March 31, 2023	**$ 904**	**$ 384**	**$ 95**	**$ 56**	**$ 1,439**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities at March 31, 2023 were as follows:

	Mar 31 2023	Dec 31 2022
Lease liabilities	**$ 1,535**	$ 1,540
Less: current portion	**244**	244
	$ 1,291	$ 1,296

Total cash outflows for leases for the three months ended March 31, 2023, including payments related to short-term leases not reported as lease assets, were $337 million (three months ended March 31, 2022 – $267 million). Interest expense on leases for the three months ended March 31, 2023 was $16 million (three months ended March 31, 2022 – $15 million).

6. INVESTMENTS

As at March 31, 2023, the Company had the following investment:

	Mar 31 2023	Dec 31 2022
Investment in PrairieSky Royalty Ltd.	**$ 484**	$ 491

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

	Three Months Ended	
	Mar 31 2023	Mar 31 2022
Loss (gain) from investments	**$ 7**	$ (83)
Dividend income	**(6)**	(3)
	$ 1	$ (86)

The Company's 22.6 million share investment in PrairieSky Royalty Ltd. does not constitute significant influence, and is accounted for at fair value through profit or loss, measured at each reporting date. As at March 31, 2023, the market price per common share was $21.40 (December 31, 2022 – $21.70; March 31, 2022 – $17.29).

7. OTHER LONG-TERM ASSETS

		Mar 31 2023		Dec 31 2022
Prepaid cost of service tolls	**$**	**195**	$	199
Long-term inventory		**138**		137
Risk management (note 15)		**1**		9
Long-term contracts, prepayments and other [(1)]		**359**		269
		693		614
Less: current portion		**65**		61
	$	**628**	$	553

(1) Includes physical product sales contracts, accrued interest on the deferred PRT recovery, and the unamortized portion of the Company's share bonus program.

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, an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 16). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 17).

The carrying value of the Company's interest in NWRP is $nil, and as at March 31, 2023, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $567 million (December 31, 2022 – $551 million). For the three months ended March 31, 2023, the unrecognized share of the equity loss was $16 million (three months ended March 31, 2022 – unrecognized equity loss of $10 million).

8. LONG-TERM DEBT

		Mar 31 2023		Dec 31 2022
Canadian dollar denominated debt, unsecured				
Medium-term notes	**$**	**1,691**	$	1,702
US dollar denominated debt, unsecured				
Commercial paper (March 31, 2023 – US$436 million; December 31, 2022 – US$nil)		**588**		—
US dollar debt securities (March 31, 2023 – US$7,250 million; December 31, 2022 – US$7,250 million)		**9,811**		9,812
		10,399		9,812
Long-term debt before transaction costs and original issue discounts, net		**12,090**		11,514
Less: original issue discounts, net [(1)]		**12**		13
transaction costs [(1) (2)]		**54**		56
		12,024		11,445
Less: current portion of commercial paper		**588**		—
current portion of other long-term debt [(1) (2)]		**404**		404
	$	**11,032**	$	11,041

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

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

Bank Credit Facilities and Commercial Paper

As at March 31, 2023, the Company had undrawn revolving bank credit facilities of $5,520 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. At March 31, 2023, the Company had $588 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 $500 million revolving credit facility, maturing February 2024;
- a $2,425 million revolving syndicated credit facility, maturing June 2024; and
- a $2,495 million revolving syndicated credit facility, with $70 million maturing June 2023, and $2,425 million maturing June 2025.

Borrowings under the Company's revolving credit facilities may be made by way of pricing referenced to Canadian dollar bankers' acceptances, US dollar bankers’ acceptances, LIBOR, SOFR, 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's weighted average interest rate on bank credit facilities and commercial paper outstanding as at March 31, 2023 was 5.3% (March 31, 2022 – 1.4%), and on total long-term debt outstanding for the three months ended March 31, 2023 was 4.7% (three months ended March 31, 2022 – 4.0%).

As at March 31, 2023, letters of credit and guarantees aggregating to $553 million were outstanding.

Medium-Term Notes

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

US Dollar Debt Securities

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

9. OTHER LONG-TERM LIABILITIES

	Mar 31 2023	Dec 31 2022
Asset retirement obligations	**$ 6,872**	$ 6,908
Lease liabilities (note 5)	**1,535**	1,540
Share-based compensation	**752**	832
Transportation and processing contracts	**139**	159
Risk management (note 15)	**9**	3
Other	**63**	92
	9,370	9,534
Less: current portion	**1,375**	1,373
	$ 7,995	$ 8,161

Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 5.6% (December 31, 2022 – 5.6%) and inflation rates of up to 2% (December 31, 2022 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Mar 31 2023	Dec 31 2022
Balance – beginning of period	**$ 6,908**	$ 6,806
Liabilities incurred	**9**	20
Liabilities acquired, net	**—**	11
Liabilities settled	**(137)**	(449)
Asset retirement obligation accretion	**92**	281
Revision of cost, inflation and timing estimates (1)	**—**	897
Impact of regulatory changes (2)	**—**	982
Change in discount rates	**—**	(1,698)
Foreign exchange adjustments	**—**	58
Balance – end of period	**6,872**	6,908
Less: current portion	**485**	495
	$ 6,387	$ 6,413

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to the acceleration of abandonment of Ninian field assets in the North Sea at December 31, 2022.

(2) Reflects changes to the estimated timing of settlement of the Company's asset retirement obligations due to provincial regulatory changes in Alberta, British Columbia, and Saskatchewan in 2022.

Share-Based Compensation

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

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

	Mar 31 2023	Dec 31 2022
Balance – beginning of period	**$ 832**	$ 489
Share-based compensation expense	**66**	804
Cash payment for stock options surrendered and PSUs vested	**(4)**	(79)
Transferred to common shares	**(143)**	(387)
Other	**1**	5
Balance – end of period	**752**	832
Less: current portion	**575**	559
	$ 177	$ 273

10. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
Expense (recovery)	**Mar 31 2023**	Mar 31 2022
Current corporate income tax – North America [(1)]	**$ 480**	$ 834
Current corporate income tax – North Sea	**6**	7
Current corporate income tax – Offshore Africa	**10**	12
Current PRT [(2)] – North Sea	**(40)**	(7)
Other taxes	**3**	5
Current income tax	**459**	851
Deferred corporate income tax	**23**	125
Deferred PRT [(2)] – North Sea	**7**	—
Deferred income tax	**30**	125
Income tax	**$ 489**	$ 976

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

(2) Petroleum Revenue Tax.

11. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2023	
Issued common shares	**Number of shares** (thousands)	**Amount**
Balance – beginning of period	**1,102,636**	**$ 10,294**
Issued upon exercise of stock options	**3,654**	**143**
Previously recognized liability on stock options exercised for common shares	**—**	**143**
Purchase of common shares under Normal Course Issuer Bid	**(8,900)**	**(84)**
Balance – end of period	**1,097,390**	**$ 10,496**

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 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.90 per common share, beginning with the dividend paid on April 5, 2023. On November 2, 2022, the Board of Directors approved a 13% increase in the quarterly dividend to $0.85 per common share. On August 3, 2022, the Board of Directors approved a special dividend of $1.50 per common share. On March 2, 2022, the Board of Directors approved a 28% increase in the quarterly dividend to $0.75 per common share, from $0.5875 per common share.

Normal Course Issuer Bid

On March 8, 2023, 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 92,296,006 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2023 and ending March 12, 2024.

For the three months ended March 31, 2023, the Company purchased 8,900,000 common shares at a weighted average price of $76.96 per common share for a total cost of $685 million. Retained earnings were reduced by $601 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2023, the Company purchased 2,100,000 common shares at a weighted average price of $80.60 per common share for a total cost of $169 million.

Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding at March 31, 2023:

	Three Months Ended Mar 31, 2023		
	Stock options (thousands)		**Weighted average exercise price**
Outstanding – beginning of period	**31,150**	**$**	**42.37**
Granted	**5,829**	**$**	**79.74**
Exercised for common shares	**(3,654)**	**$**	**39.03**
Surrendered for cash settlement	**(92)**	**$**	**39.20**
Forfeited	**(600)**	**$**	**50.25**
Outstanding – end of period	**32,633**	**$**	**49.28**
Exercisable – end of period	**6,043**	**$**	**37.66**

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 INCOME (LOSS)

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

		Mar 31 2023		Mar 31 2022
Derivative financial instruments designated as cash flow hedges	**$**	**74**	$	77
Foreign currency translation adjustment		**133**		(115)
	$	**207**	$	(38)

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, enabling the Company to access capital markets to sustain its on-going operations and 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 ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. 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. As at March 31, 2023, the ratio was below the target range at 23.6%.

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

	Mar 31 2023	Dec 31 2022
Long-term debt	**$ 12,024**	$ 11,445
Less: cash and cash equivalents	**92**	920
Long-term debt, net	**$ 11,932**	$ 10,525
Total shareholders' equity	**$ 38,585**	$ 38,175
Debt to book capitalization	**23.6%**	21.6%

The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at March 31, 2023, the Company was in compliance with this covenant.

14. NET EARNINGS PER COMMON SHARE

		Three Months Ended	
		Mar 31 2023	Mar 31 2022
Weighted average common shares outstanding – basic (thousands of shares)		**1,100,463**	1,164,793
Effect of dilutive stock options (thousands of shares)		**11,579**	15,557
Weighted average common shares outstanding – diluted (thousands of shares)		**1,112,042**	1,180,350
Net earnings		**$ 1,799**	$ 3,101
Net earnings per common share	– basic	**$ 1.63**	$ 2.66
	– diluted	**$ 1.62**	$ 2.63

15. FINANCIAL INSTRUMENTS

The Company's financial instruments are comprised of cash and cash equivalents, accounts receivable, investments, risk management assets and liabilities, accounts payable, accrued liabilities, lease liabilities and long-term debt. These financial instruments, with the exception of investments and risk management assets and liabilities, are classified as financial assets and liabilities at amortized cost. Investments are classified as financial assets at fair value through profit or loss. Risk management assets and liabilities are classified as derivatives held for trading or as cash flow hedges.

The estimated fair values of derivative financial instruments in Level 2 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications, including quoted forward prices for commodities, foreign exchange rates, interest yield curves and other volatility factors.

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)	**Mar 31 2023**	Dec 31 2022
Balance – beginning of period	**$ 6**	$ 55
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1]	**(14)**	70
Foreign exchange	**—**	(119)
Balance – end of period	**(8)**	6
Less: current portion	**(8)**	—
	$ —	$ 6

(1) Risk management assets and liabilities are disclosed in note 7 and note 9, respectively.

The net loss from risk management activities was as follows:

	Three Months Ended	
	Mar 31 2023	Mar 31 2022
Net realized risk management loss	**$ 1**	$ 32
Net unrealized risk management loss	**20**	26
	$ 21	$ 58

The carrying amounts of the Company's financial instruments approximated their fair value, except for fixed rate long-term debt. The Company's financial instruments are categorized as Level 1 with the exception of risk management assets and liabilities which are categorized as Level 2. There were no transfers between Level 1, 2 and 3 financial instruments. The fair value of the Company's fixed rate long-term debt is outlined below:

	Mar 31, 2023	
Asset (liability)	**Carrying amount**	**Level 1 Fair value**
Fixed rate long-term debt [1] [2]	**$ (11,436)**	**$ (11,276)**

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

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

Financial Risk Factors

The Company’s financial risks are consistent with those discussed in notes 1, 4 and 19 of the Company’s audited financial statements for the year ended December 31, 2022.

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 rate 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.

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. At March 31, 2023, the Company had no significant 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.

As at March 31, 2023, the Company had US$1,446 million of foreign currency forward contracts outstanding (December 31, 2022 - US$1,017 million), with original terms of up to 90 days, of which US$1,010 million were designated as derivatives held for trading (December 31, 2022 - US$1,017 million) and US$436 million were designated as cash flow hedges (December 31, 2022 - US$nil).

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. At March 31, 2023, substantially all of the Company's accounts receivable were due within normal trade terms.

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. At March 31, 2023, the Company had net risk management assets of $nil with specific counterparties related to derivative financial instruments (December 31, 2022 – $7 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.

As at March 31, 2023, 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	$	1,220	$	—	$	—	$	—
Accrued liabilities	$	3,817	$	—	$	—	$	—
Long-term debt (1)	$	992	$	1,809	$	3,168	$	6,121
Other long-term liabilities (2)	$	253	$	158	$	413	$	720
Interest and other financing expense (3)	$	629	$	589	$	1,400	$	3,664

(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, $244 million; one to less than two years, $158 million; two to less than five years, $413 million; and thereafter, $720 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates at March 31, 2023.

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 March 31, 2023:

		Remaining 2023		2024		2025		2026		2027		Thereafter
Product transportation and processing (1)	$	892	$	1,387	$	1,238	$	1,147	$	1,096	$	11,273
North West Redwater Partnership service toll (2)	$	114	$	154	$	153	$	135	$	120	$	4,952
Offshore vessels and equipment	$	31	$	35	$	—	$	—	$	—	$	—
Field equipment and power	$	30	$	28	$	26	$	23	$	22	$	215
Other	$	18	$	24	$	22	$	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 $2,913 million of interest payable over the 40-year tolling period, ending in 2058 (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 Three Months Ended Mar 31		North Sea Three Months Ended Mar 31		Offshore Africa Three Months Ended Mar 31		Total Exploration and Production Three Months Ended Mar 31	
	2023	2022	**2023**	2022	**2023**	2022	**2023**	2022
Segmented product sales								
Crude oil and NGLs	**3,749**	5,539	**—**	127	**92**	217	**3,841**	5,883
Natural gas	**807**	930	**3**	5	**12**	14	**822**	949
Other income and revenue [1]	**11**	70	**—**	1	**2**	2	**13**	73
Total segmented product sales	**4,567**	6,539	**3**	133	**106**	233	**4,676**	6,905
Less: royalties	**(491)**	(907)	**—**	—	**(10)**	(11)	**(501)**	(918)
Segmented revenue	**4,076**	5,632	**3**	133	**96**	222	**4,175**	5,987
Segmented expenses								
Production	**1,002**	887	**3**	67	**27**	28	**1,032**	982
Transportation, blending and feedstock	**1,546**	1,752	**—**	2	**—**	—	**1,546**	1,754
Depletion, depreciation and amortization	**890**	878	**1**	29	**35**	51	**926**	958
Asset retirement obligation accretion	**59**	35	**11**	7	**2**	2	**72**	44
Risk management activities (commodity derivatives)	**20**	49	**—**	—	**—**	—	**20**	49
Total segmented expenses	**3,517**	3,601	**15**	105	**64**	81	**3,596**	3,787
Segmented earnings (loss)	**559**	2,031	**(12)**	28	**32**	141	**579**	2,200
Non–segmented expenses								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management activities (other)								
Foreign exchange gain								
Loss (gain) from investments								
Total non–segmented expenses								
Earnings before taxes								
Current income tax								
Deferred income tax								
Net earnings								

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading Three Months Ended Mar 31 **2023**	 2022	Midstream and Refining Three Months Ended Mar 31 **2023**	 2022	Inter–segment elimination and other Three Months Ended Mar 31 **2023**	 2022	Total Three Months Ended Mar 31 **2023**	 2022
Segmented product sales								
Crude oil and NGLs [2]	**4,482**	4,851	**21**	20	**68**	19	**8,412**	10,773
Natural gas	**—**	—	**—**	—	**29**	53	**851**	1,002
Other income and revenue [1]	**19**	35	**250**	249	**3**	—	**285**	357
Total segmented product sales	**4,501**	4,886	**271**	269	**100**	72	**9,548**	12,132
Less: royalties	**(417)**	(537)	**—**	—	**—**	—	**(918)**	(1,455)
Segmented revenue	**4,084**	4,349	**271**	269	**100**	72	**8,630**	10,677
Segmented expenses								
Production	**1,042**	977	**78**	66	**12**	15	**2,164**	2,040
Transportation, blending and feedstock [2]	**550**	463	**153**	179	**85**	59	**2,334**	2,455
Depletion, depreciation and amortization	**488**	445	**4**	4	**—**	—	**1,418**	1,407
Asset retirement obligation accretion	**20**	15	**—**	—	**—**	—	**92**	59
Risk management activities (commodity derivatives)	**—**	—	**—**	—	**—**	—	**20**	49
Total segmented expenses	**2,100**	1,900	**235**	249	**97**	74	**6,028**	6,010
Segmented earnings (loss)	**1,984**	2,449	**36**	20	**3**	(2)	**2,602**	4,667
Non–segmented expenses								
Administration							**106**	116
Share-based compensation							**66**	534
Interest and other financing expense							**154**	163
Risk management activities (other)							**1**	9
Foreign exchange gain							**(14)**	(146)
Loss (gain) from investments							**1**	(86)
Total non-segmented expenses							**314**	590
Earnings before taxes							**2,288**	4,077
Current income tax							**459**	851
Deferred income tax							**30**	125
Net earnings							**1,799**	3,101

(1) Includes the sale of diesel and other refined products in the Midstream and Refining segment, and other income.

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

Capital Expenditures [1]

	Three Months Ended					
	Mar 31, 2023			Mar 31, 2022		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America	**$ 28**	**$ (10)**	**$ 18**	$ 18	$ (1)	$ 17
Offshore Africa	**—**	**—**	**—**	1	—	1
	28	**(10)**	**18**	19	(1)	18
Property, plant and equipment						
Exploration and Production						
North America	**856**	**(189)**	**667**	1,027	(69)	958
North Sea	**3**	**—**	**3**	11	—	11
Offshore Africa	**23**	**—**	**23**	12	—	12
	882	**(189)**	**693**	1,050	(69)	981
Oil Sands Mining and Upgrading	**336**	**(50)**	**286**	312	(73)	239
Midstream and Refining	**3**	**—**	**3**	2	—	2
Head office	**8**	**—**	**8**	5	—	5
	1,229	**(239)**	**990**	1,369	(142)	1,227
	$ 1,257	**$ (249)**	**$ 1,008**	$ 1,388	$ (143)	$ 1,245

(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.

Segmented Assets

	Mar 31 2023	Dec 31 2022
Exploration and Production		
North America	**$ 30,294**	$ 31,135
North Sea	**407**	378
Offshore Africa	**1,341**	1,322
Other	**69**	54
Oil Sands Mining and Upgrading	**42,026**	42,102
Midstream and Refining	**949**	979
Head office	**174**	172
	$ 75,260	$ 76,142

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 2021. These ratios are based on the Company's interim consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the twelve month period ended March 31, 2023:	
Interest coverage (times)	
Net earnings (1)	23.1x
Adjusted funds flow (2)	39.4x

(1) Net earnings plus income taxes and interest expense; divided by interest expense.

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

This Page Left Intentionally Blank

CORPORATE INFORMATION

Board of Directors

Catherine M. Best, FCA, ICD.D
M. Elizabeth Cannon, O.C.
N. Murray Edwards, O.C.
Christopher L. Fong
Ambassador Gordon D. Giffin
Wilfred A. Gobert
Steve W. Laut
Tim S. McKay
Honourable Frank J. McKenna, P.C., O.C., O.N.B., Q.C.
David A. Tuer
Annette M. Verschuren, O.C.

Officers

N. Murray Edwards
Executive Chairman
Tim S. McKay
President
Trevor J. Cassidy
Chief Operating Officer, Exploration and Production
Scott G. Stauth
Chief Operating Officer, Oil Sands
Mark A. Stainthorpe
Chief Financial Officer and Senior Vice-President, Finance
Troy J.P. Andersen
Senior Vice-President, Canadian Conventional Field Operations
Calvin J. Bast
Senior Vice-President, Production
Jay E. Froc
Senior Vice-President, Oil Sands Mining and Upgrading
Dwayne F. Giggs
Senior Vice-President, Exploration
Dean W. Halewich
Senior Vice-President, Safety, Risk Management and Innovation
Ron K. Laing
Senior Vice-President, Corporate Development and Land
Warren P. Raczynski
Senior Vice-President, Thermal
Robin S. Zabek
Senior Vice-President, Exploitation
Brenda G. Balog
Vice-President, Legal and General Counsel
Victor C. Darel
Vice-President, Finance and Principal Accounting Officer
Erin L. Lunn
Vice-President, Land
Mark A. Overwater
Vice-President, Marketing
Kyle G. Pisio
Vice-President, Drilling, Completions and Asset Retirement
Roy D. Roth
Vice-President, Facilities and Pipelines
Kara L. Slemko
Vice-President, Corporate Development and Commercial Operations
Paul M. Mendes
Corporate Secretary and Executive Counsel

CNR International (U.K.) Limited
Aberdeen, Scotland
Barry Duncan
Managing Director and
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