



# FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2025

TSX & NYSE: CNQ

## CANADIAN NATURAL RESOURCES LIMITED 2025 FIRST QUARTER RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's Q1/25 results, "We have a long track record of being an industry leading effective and efficient producer while consistently delivering top tier operational and financial performance. All our employees are shareholders, with a strong focus on continuous improvement, consistently driving strong results. In Q1/25 we achieved record quarterly production of approximately 1,582,000 BOE/d, which included record quarterly liquids production of approximately 1,174,000 bbl/d, 79% of which was long life low decline production and record quarterly natural gas production of 2,451 MMcf/d.

At our world class Oil Sands Mining and Upgrading assets, we achieved record quarterly Synthetic Crude Oil ("SCO") production of approximately 595,000 bbl/d resulting from a high utilization rate of 106% in Q1/25, anchored by industry leading SCO operating costs of \$21.88/bbl (US\$15.25/bbl), which drove significant free cash flow in the quarter. Importantly, in 2024 our annual Oil Sands Mining and Upgrading operating costs were in the range of \$7.00/bbl to \$10.00/bbl lower than our peer average. This equates to incremental annual margin of approximately \$1.2 billion to \$1.7 billion, based on our 2024 annual production.

Following our first few months of operating the Duvernay assets acquired in December 2024 we are achieving strong production results and cost reductions. We are confident we will add more value than we planned for at the time of the acquisition. This is made possible through our commitment to continuous improvement and a strong team culture that focuses on improving our already top tier operating costs, driving execution of organic growth opportunities and maximizing value to shareholders.

Canadian Natural's constant focus on continuous improvement has resulted in capturing cost efficiencies throughout our operations year to date. As a result of these efficiencies, we are in a position to reduce our 2025 capital budget by \$100 million, resulting in an updated total capital forecast of \$6.05 billion, excluding abandonment expenditures. This reduction in our 2025 capital will have no impact on our planned operating activities or targeted production levels for 2025."

Canadian Natural's Chief Financial Officer, Victor Darel, added "In Q1/25, we achieved strong financial results, including adjusted net earnings of \$2.4 billion or \$1.16 per share and adjusted funds flow of \$4.5 billion, or \$2.16 per share. We returned approximately \$1.7 billion to our shareholders in Q1/25, including \$1.2 billion in dividends and \$0.5 billion in share repurchases. At the same time we strengthened our balance sheet by reducing net debt in the quarter by approximately \$1.4 billion from December 31, 2024 levels.

We are committed to maximizing shareholder value and increasing sustainable returns to shareholders. As previously announced, in March 2025 the Board of Directors approved a 4% increase to our quarterly dividend to \$0.5875 per common share or \$2.35 per common share annualized, with 2025 being the 25<sup>th</sup> consecutive year of dividend increases by Canadian Natural, with a compound annual growth rate ("CAGR") of 21% over that time.

Our business model is robust and sustainable as our top tier US\$ WTI breakeven, defined as the adjusted funds flow required to cover maintenance capital and dividends, remains in the low to mid-US\$40 per barrel range. Our balance sheet is already very strong and we improved it further by reducing net debt by approximately \$1.4 billion in Q1/25, as mentioned above, and maintained liquidity of approximately \$5.1 billion as at March 31, 2025, providing significant flexibility.

Our leading financial results combined with our top tier, safe, reliable, effective and efficient operations provide us with unique competitive advantages, all of which drive material free cash flow generation and strong returns on capital."



- Canadian Natural continues to focus on safe, effective and efficient operations delivering record quarterly average production in Q1/25 of 1,582,348 BOE/d, consisting of record total liquids production of 1,173,804 bbl/d and record natural gas production of 2,451 MMcf/d.
- Canadian Natural's world class Oil Sands Mining and Upgrading assets delivered record quarterly production of 595,116 bbl/d of SCO in Q1/25, an increase of 34% or approximately 150,000 bbl/d from Q1/24 levels.
  - Gross production of approximately 630,000 bbl/d in Q1/25, with upgrader utilization of 106%, was the highest quarterly Oil Sands Mining and Upgrading gross production in the Company's history, achieved through successes from the recently completed Reliability Enhancement Project and Scotford Upgrader debottleneck work, driving strong performance.
    - When comparing utilization over the last 5 years Canadian Natural's was approximately 8% higher versus a comparable peer average. This equates to approximately 40,000 bbl/d of incremental annual production based on 2024 capacity.
    - Industry leading quarterly Oil Sands Mining and Upgrading operating costs of \$21.88/bbl (US\$15.25/bbl) of SCO were achieved in Q1/25, a decrease of 12% from Q1/24 levels.
    - Canadian Natural's high value SCO represented approximately 51% of the Company's total liquids volumes in Q1/25 and captured strong quarterly realized SCO pricing of \$95.52/bbl, generating significant free cash flow.
  - Thermal in situ quarterly production averaged 284,706 bbl/d in Q1/25, an increase of 6% or approximately 16,500 bbl/d from Q1/24 levels as a result of the Company's capital efficient thermal pad add development program. Results have been strong from the two Cyclic Steam Stimulation ("CSS") pads that came on production ahead of schedule at Primrose in Q4/24 and Q1/25.
    - Quarterly thermal in situ operating costs were strong, averaging \$11.23/bbl (US\$7.83/bbl) in Q1/25, a decrease of 20% from Q1/24 levels, primarily reflecting higher production volumes and lower energy costs.
- On the recently acquired Duvernay assets, Canadian Natural's effective and efficient operations, area synergies and expertise in similar plays, such as the Montney, have resulted in both capital and operating cost efficiencies. Additionally, we are on track to achieve 2025 budget production of approximately 60,000 BOE/d.
  - By optimizing well length and completions design combined with top tier execution, we are drilling longer wells with improved reservoir access at lower costs. On a length normalized basis, combined drilling and completion costs for 2025 are targeting an improvement of approximately 14% or \$1.8 million per well compared to 2024 costs.
  - The Company is targeting to drill 43 gross wells in the Duvernay as part of the 2025 capital development program.
  - Operating costs in Q1/25 were strong, averaging approximately \$9.52/BOE.

## RETURNS TO SHAREHOLDERS

- Canadian Natural has a strong history of growing its sustainable dividend with 2025 being the 25<sup>th</sup> consecutive year of dividend increases with a CAGR of 21% over that time.
  - Returns to shareholders in Q1/25 were strong, totaling approximately \$1.7 billion, comprised of \$1.2 billion of dividends and \$0.5 billion through the repurchase and cancellation of approximately 11.2 million common shares at a weighted average price of \$43.66 per share.
  - Year to date in 2025, up to and including May 7, 2025, the Company has returned a total of approximately \$3.1 billion directly to shareholders through \$2.4 billion in dividends and \$0.7 billion through the repurchase and cancellation of approximately 15.8 million common shares.
  - Subsequent to quarter end, Canadian Natural declared a quarterly cash dividend on its common shares of \$0.5875 per common share. The quarterly dividend will be payable on July 3, 2025 to shareholders of record at the close of business on June 13, 2025.
    - As previously announced, on March 6, 2025 the Board of Directors increased the quarterly dividend by 4% to \$0.5875 per common share. This demonstrates 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 reserves and asset base.

## OPERATIONS REVIEW AND CAPITAL ALLOCATION

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

Underpinning this asset base is the Company's long life low decline production, representing approximately 77% of total budgeted liquids production in 2025, 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 landbase which enables large, repeatable drilling programs that can be optimized over time. Additionally, Canadian Natural maximizes long-term value by maintaining high ownership and operatorship of its assets, allowing the Company to control the nature, timing and extent of development. Low capital exposure projects can be stopped or started relatively quickly 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			
	March 31, 2025		March 31, 2024	
(number of wells)	Gross	Net	Gross	Net
Crude oil <sup>(1)</sup>	75	74	62	61
Natural gas	23	19	23	16
Dry	1	1	—	—
Subtotal	99	94	85	77
Stratigraphic test / service wells	484	462	452	386
Total	583	556	537	463
Success rate (excluding stratigraphic test / service wells)		99%		100%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 94 net crude oil and natural gas producer wells in Q1/25, 17 more than in Q1/24.

## North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Crude oil and NGLs production (bbl/d)	<b>276,532</b>	255,729	237,481
Net wells targeting crude oil	<b>57</b>	84	38
Net successful wells drilled	<b>56</b>	84	38
Success rate	<b>98%</b>	100%	100%

- North America E&P liquids production, excluding thermal in situ, averaged 276,532 bbl/d in Q1/25, a 16% increase from Q1/24 levels, reflecting production volumes from the Duvernay assets acquired in December 2024, along with strong organic growth from our liquids-rich natural gas and primary heavy crude oil assets.
  - Primary heavy crude oil production averaged 85,604 bbl/d in Q1/25, a 9% increase from Q1/24 levels, reflecting strong drilling results from the Company's multilateral wells, partially offset by natural field declines.
    - Continuing to build on the Company's highly successful multilateral drilling program, Canadian Natural targets to drill 156 net primary heavy crude oil multilateral wells in 2025.
    - Operating costs in the Company's primary heavy crude oil operations averaged \$18.13/bbl (US\$12.63/bbl) in Q1/25, a decrease of 5% from Q1/24 levels, primarily reflecting higher production volumes and lower energy costs.
  - Pelican Lake production averaged 43,175 bbl/d in Q1/25 a decrease of 4% from Q1/24 levels, reflecting low natural field declines from this long life low decline asset.
    - Operating costs at Pelican Lake averaged \$9.77/bbl (US\$6.81/bbl) in Q1/25, comparable to Q1/24 levels.
  - North America light crude oil and NGLs production averaged 147,753 bbl/d in Q1/25, an increase of 30% or approximately 34,000 bbl/d compared to Q1/24 levels, primarily driven by the recently acquired Duvernay assets and strong drilling results in our liquids-rich natural gas assets.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged \$13.15/bbl (US\$9.16/bbl) in Q1/25, a decrease of 14% from Q1/24 levels, primarily reflecting higher production volumes and lower energy costs.

### North America Natural Gas

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Natural gas production (MMcf/d)	<b>2,436</b>	2,273	2,135
Net wells targeting natural gas	<b>19</b>	14	16
Net successful wells drilled	<b>19</b>	14	16
Success rate	<b>100%</b>	100%	100%

- North America natural gas production averaged 2,436 MMcf/d in Q1/25, an increase of 14% from Q1/24 levels, driven by the recently acquired Duvernay assets and strong drilling results in the Company's liquids-rich natural gas assets. The Company remains focused on delivering strong returns on organic growth with our liquids-rich natural gas activity in the Duvernay, Montney and Deep Basin.
  - North America natural gas operating costs averaged \$1.16/Mcf in Q1/25, a decrease of 9% from Q1/24 levels, primarily reflecting higher production volumes.

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Bitumen production (bbl/d)	<b>284,706</b>	276,231	268,155
Net wells targeting bitumen	<b>18</b>	16	23
Net successful wells drilled	<b>18</b>	16	23
Success rate	<b>100%</b>	100%	100%

- Thermal in situ production averaged 284,706 bbl/d in Q1/25, an increase of 6% or approximately 16,500 bbl/d from Q1/24 levels as a result of the Company's capital efficient thermal pad add development program. Results have been strong from the two CSS pads that came on production ahead of schedule at Primrose in Q4/24 and Q1/25.
  - Quarterly thermal in situ operating costs were strong, averaging \$11.23/bbl (US\$7.83/bbl) in Q1/25, a decrease of 20% from Q1/24 levels, primarily reflecting higher production volumes and lower energy costs.
- Canadian Natural has significant thermal in situ facility processing capacity of approximately 340,000 bbl/d, resulting in 70,000 bbl/d of available capacity. The Company has decades of strong capital efficient drill to fill growth opportunities on its long life low decline thermal in situ assets, which we continue to develop in a disciplined manner to deliver safe and reliable thermal in situ production.
  - At Primrose, following strong results from the recently drilled CSS pads, the Company is planning to reallocate a portion of pad add capital in 2025 to Primrose from Kirby to maximize returns. The Company now targets to drill a CSS pad in Q4/25 with production targeted to come on in 2026.
  - At Jackfish, the Company finished drilling a SAGD pad in Q4/24, with production targeted to come on in Q3/25.
  - At Pike, the Company has completed drilling one SAGD pad and is currently drilling a second SAGD pad, both of which will be tied into existing Jackfish facilities. These two pads are targeted to come on production in 2026 and keep the Jackfish plants at full capacity.
  - At Kirby, the Company recently finished drilling a SAGD pad which is targeted to come on production in Q4/25.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain thermal in situ assets with an objective to increase bitumen production while reducing the Steam to Oil Ratio ("SOR") and optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
  - At the Company's commercial scale solvent SAGD pad at Kirby North, we began solvent injection in June 2024 and solvent recoveries continue to meet expectations, exceeding 80%. Pad performance monitoring has identified several well pair workover opportunities to further enhance SORs, solvent recovery and production trends. These workovers are targeted to be completed in Q2/25 with continued monitoring over the second half of 2025.
  - At Primrose, the Company is continuing to operate its solvent enhanced oil recovery pilot in the steam flood area to optimize solvent efficiency and to further evaluate this commercial development opportunity.

## North America Oil Sands Mining and Upgrading

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Synthetic crude oil production (bbl/d) <sup>(1)(2)</sup>	<b>595,116</b>	534,631	445,209

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

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

- Oil Sands Mining and Upgrading continues to outperform expectations, through our relentless focus on continuous improvement combined with strong performance from the completed Reliability Enhancement Project at Horizon and Debottleneck Project at the Scotford Upgrader. As a result, the Company achieved strong operational results in Q1/25 as follows:
  - Record quarterly production of 595,116 bbl/d of SCO was achieved in Q1/25, an increase of 34% or approximately 150,000 bbl/d from Q1/24 levels, reflecting strong operating results, the acquisition of an additional 20% working interest in AOSP in December 2024, and planned and unplanned maintenance a year earlier in Q1/24.
    - Gross production of approximately 630,000 bbl/d in Q1/25, with upgrader utilization of 106%, was the highest quarterly Oil Sands Mining and Upgrading gross production in the Company's history, as a result of continuous improvement initiatives resulting in strong performance.
    - Industry leading Oil Sands Mining and Upgrading operating costs of \$21.88/bbl (US\$15.25/bbl) of SCO were achieved in Q1/25, a decrease of 12% from Q1/24 levels. The decrease in operating costs in Q1/25 compared to Q1/24 was due primarily to higher production volumes and lower energy costs.
    - Canadian Natural's high value SCO represented approximately 51% of the Company's total liquids volumes in Q1/25 and captured strong quarterly realized SCO pricing of \$95.52/bbl, generating significant free cash flow.
- As previously announced, the planned AOSP turnaround began on April 4, 2025 and is targeted for 73 days. During this turnaround, the Scotford Upgrader will operate at reduced rates, impacting net annual average production by approximately 31,000 bbl/d, based on Canadian Natural's current 90% working interest.
- At Horizon, the Company completed the Reliability Enhancement Project in 2024 which increased the capacity of the zero decline, high value SCO production at Horizon to 264,000 bbl/d over a two year timeframe by shifting the planned turnarounds to once every two years from the previous annual cycle. As a result, 2025 will be the first year without a planned turnaround, resulting in high targeted utilization at Horizon.
  - With additional infrastructure in place following the completion of this project, the Company can perform certain maintenance activities with zero production impact. Capital savings are targeted to be approximately \$75 million in 2025 from 2024 levels as a result of no planned turnaround impacting production.
- At Horizon, the Company is progressing its Naphtha Recovery Unit Tailings Treatment ("NRUTT") project which targets incremental production of approximately 6,300 bbl/d of SCO following mechanical completion in Q3/27.

## International Exploration and Production

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Crude oil production (bbl/d)	<b>17,450</b>	23,411	24,823
Natural gas production (MMcf/d)	<b>15</b>	10	12

- International E&P crude oil production volumes averaged 17,450 bbl/d in Q1/25, a decrease of 30% compared to Q1/24 levels primarily reflecting suspended production at Baobab in Offshore Africa due to the planned life extension project on its floating production storage and offloading vessel which commenced in January 2025, which is targeted to impact 2025 net annual production by approximately 7,800 bbl/d, combined with natural field declines. Production at Baobab is targeted to resume in Q2/26.

## MARKETING

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Benchmark Commodity Prices</b>			
WTI benchmark price (US\$/bbl) <sup>(1)</sup>	\$ 71.42	\$ 70.27	\$ 76.97
WCS heavy differential (discount) to WTI (US\$/bbl) <sup>(1)</sup>	\$ (12.66)	\$ (12.55)	\$ (19.34)
WCS heavy differential as a percentage of WTI (%) <sup>(1)</sup>	18%	18%	25%
Condensate benchmark price (US\$/bbl)	\$ 69.89	\$ 70.66	\$ 72.79
SCO price (US\$/bbl) <sup>(1)</sup>	\$ 69.07	\$ 71.13	\$ 69.43
SCO premium (discount) to WTI (US\$/bbl) <sup>(1)</sup>	\$ (2.35)	\$ 0.86	\$ (7.54)
AECO benchmark price (C\$/GJ)	\$ 1.92	\$ 1.38	\$ 1.94
<b>Realized Prices</b>			
Exploration & Production liquids realized price (C\$/bbl) <sup>(2)(3)(4)(5)</sup>	\$ 79.85	\$ 75.22	\$ 70.01
SCO realized price (C\$/bbl) <sup>(1)(3)(4)(5)</sup>	\$ 95.52	\$ 95.08	\$ 88.84
Natural gas realized price (C\$/Mcf) <sup>(4)</sup>	\$ 3.13	\$ 2.02	\$ 2.55

(1) West Texas Intermediate ("WTI"); Western Canadian Select ("WCS"); Synthetic Crude Oil ("SCO").

(2) Exploration & Production crude oil and NGLs average realized price excludes SCO.

(3) Pricing is net of blending and feedstock costs.

(4) Excludes risk management activities.

(5) 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, 2025 dated May 7, 2025.

- Canadian Natural has a balanced and diverse product mix of natural gas, NGLs, heavy crude oil, light crude oil, bitumen and SCO.
- WTI prices averaged US\$71.42/bbl in Q1/25, comparable to Q4/24 and a decrease of US\$5.55/bbl compared to Q1/24 levels. The decrease compared to Q1/24 reflected weaker global demand growth outlooks amid escalating trade tensions, combined with concerns of supply growth from non-OPEC+ producers.
- SCO pricing averaged US\$69.07/bbl in Q1/25, representing a US\$2.35/bbl discount to WTI pricing, compared to a US\$0.86/bbl premium to WTI in Q4/24 and a US\$7.54 discount to WTI in Q1/24. The SCO differential weakened in Q1/25 relative to Q4/24, driven in part by production levels in the Western Canadian Sedimentary Basin ("WCSB").
- The WCS differential to WTI averaged US\$12.66/bbl in Q1/25, comparable to Q4/24 and a US\$6.68/bbl improvement compared to the US\$19.34/bbl discount in Q1/24. The narrowing of the WCS differential to WTI in Q1/25 compared to Q1/24 primarily reflects the start-up of the TMX pipeline in Q2/24, combined with stronger United States Gulf Coast ("USGC") heavy oil pricing.
- The North West Redwater refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 83,863 bbl/d in Q1/25.
- Canadian Natural has total contracted crude oil transportation capacity of 256,500 bbl/d, with committed volumes to Canada's west coast and to the USGC of approximately 23% of 2025 budgeted liquids production. The egress supports Canadian Natural's long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.
  - The Company has total committed capacity on the TMX pipeline of 169,000 bbl/d providing access to markets on Canada's west coast.
  - Canadian Natural has total committed capacity of 77,500 bbl/d on the Flanagan South pipeline and an additional 10,000 bbl/d of committed capacity on the Keystone Base pipeline, diversifying the Company's heavy oil access to the USGC.
- AECO natural gas prices averaged \$1.92/GJ in Q1/25, a \$0.54/GJ improvement compared to Q4/24 and comparable to Q1/24. The increase in AECO natural gas pricing compared to Q4/24 primarily reflects stronger NYMEX benchmark pricing, combined with increased exports out of the WCSB. Stronger AECO pricing in Q1/25 also reflects the anticipated start-up of LNG Canada targeted for the second half of 2025.

- In 2025, the Company is targeting to use the equivalent of approximately 33% of budgeted natural gas production in its operations, with approximately 35% targeted to be sold at AECO/Station 2 pricing, and approximately 32% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value from its diversified natural gas marketing portfolio.
- As a result of Canadian Natural's diversified natural gas marketing strategy, the Company's Q1/25 realized natural gas price of \$3.13/Mcf represents a \$1.07/Mcf or 52% premium over the AECO benchmark price of \$2.06/Mcf.

## ADVISORY

### Special Note Regarding Non-GAAP and Other Financial Measures

This document 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. These financial measures are used by the Company to evaluate its financial performance, financial position and 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 document, 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 March 31, 2025, dated May 7, 2025.

### Free Cash Flow Allocation Policy

Free cash flow is a non-GAAP financial measure. 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 or maintain net debt levels, pursuant to the free cash flow allocation policy.

The Company's free cash flow is used to determine the targeted amount of shareholder returns after dividends. The amount allocated to shareholders varies depending on the Company's net debt position.

Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures. The Company targets to manage the allocation of free cash flow on a forward looking annual basis, while managing working capital and cash management as required.

Up to October 2024, before the announcement of the Chevron acquisition, the Company was targeting to allocate 100% of its free cash flow in 2024 to shareholder returns.

In October 2024, with the announcement of the Chevron acquisition, the Board of Directors adjusted the allocation of free cash flow as follows:

- 60% of free cash flow to shareholder returns and 40% to the balance sheet until net debt reaches \$15 billion.
- When net debt is between \$12 billion and \$15 billion, free cash flow allocation will be 75% to shareholder returns and 25% to the balance sheet.
- When net debt is at or below \$12 billion, free cash flow allocation will be 100% to shareholder returns.

The Company's free cash flow for the three months ended March 31, 2025 is shown below:

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Adjusted funds flow <sup>(1)</sup>	\$ 4,530	\$ 4,186	\$ 3,138
Less: Dividends on common shares	1,184	1,110	1,076
Net capital expenditures, <sup>(2)</sup> excluding net acquisition costs <sup>(3)</sup>	1,303	1,290	1,113
Abandonment expenditures	188	151	162
Free cash flow	\$ 1,855	\$ 1,635	\$ 787

(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, 2025, dated May 7, 2025.

(2) Net Capital expenditures is a Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months ended March 31, 2025, dated May 7, 2025.

(3) Excludes net acquisition costs of \$9,058 million for the three months ended December 31, 2024 related to the acquisition of assets in the period.

### 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.

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Long-term debt	\$ 17,428	\$ 18,819	\$ 11,040
Less: cash and cash equivalents	93	131	767
Long-term debt, net	\$ 17,335	\$ 18,688	\$ 10,273

**Breakeven WTI Price**

The breakeven 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 breakeven WTI price a key measure in evaluating its performance, as it demonstrates the efficiency and profitability of the Company's activities. The breakeven 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.

**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 includes acquisition capital related to a number of acquisitions for which agreements between parties have been reached as at the time of the Company's 2025 budget press release on January 9, 2025. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for more details on net capital expenditures.

The 2025 capital budget reflects budgeted net capital expenditures, before abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these budgeted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries. Current tax recoveries are refundable at a rate of approximately 23% in Canada and a combined current income tax and Petroleum Revenue Tax ("PRT") rate approximating 70% to 75% in the UK portion of the North Sea. The Company is eligible to recover interest on refunded PRT previously paid.

**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.

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# MANAGEMENT'S DISCUSSION AND ANALYSIS

## ADVISORY

### Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "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 the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, abandonment 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, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, 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 ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish") 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 abandonment and decommissioning of certain assets and the timing thereof; 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 materiality of the impact of tax interpretations and litigation on the Company's results, 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 conflicts in the Middle East and in Ukraine, 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, and 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; changes and uncertainty in the international trade environment, including with respect to tariffs, export restrictions, embargoes and key trade agreements (including tariffs on certain goods announced by the US government and Canadian countermeasures subsequently announced, both of which are anticipated to evolve and may be continued, suspended, increased, decreased, or imposed on additional goods); uncertainty in the regulatory framework governing greenhouse gas emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps; political uncertainty, including changes in government, actions of or against terrorists, insurgent groups or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company to complete capital programs; the Company's 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 the mining, extracting or upgrading the Company's bitumen products; availability and cost of financing; the Company's 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, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; 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, the imposition of tariffs, embargoes or export restrictions on the Company's products (including tariffs on certain goods announced by the US government and Canadian countermeasures subsequently announced, both of which are anticipated to evolve and may be continued, suspended, increased, decreased, or imposed on additional goods), 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 Common Share Split and Comparative Figures**

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

### **Special Note Regarding Amendments to the *Competition Act* (Canada)**

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement* which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act's* deceptive marketing practices provisions. These amendments include substantial financial penalties and, effective June 20, 2025, a private right of action which will permit private parties to seek an order from the Competition Tribunal under the deceptive marketing practices provisions. Uncertainty surrounding the interpretation and enforcement of this legislation may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

### **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, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. 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, 2025 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, 2025 in relation to the first quarter of 2024 and the fourth quarter of 2024. 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, 2024, is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca), and on EDGAR at [www.sec.gov](http://www.sec.gov). Information in such Annual Information Form and 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 7, 2025.

## FINANCIAL HIGHLIGHTS<sup>(1)</sup>

(\$ millions, except per common share amounts)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Product sales <sup>(1)</sup>	\$ 12,712	\$ 11,064	\$ 9,422
Crude oil and NGLs	\$ 11,732	\$ 10,381	\$ 8,676
Natural gas	\$ 716	\$ 451	\$ 529
Net earnings	\$ 2,458	\$ 1,138	\$ 987
Per common share			
– basic	\$ 1.17	\$ 0.54	\$ 0.46
– diluted	\$ 1.17	\$ 0.54	\$ 0.46
Adjusted net earnings from operations <sup>(2)</sup>	\$ 2,436	\$ 1,977	\$ 1,474
Per common share			
– basic <sup>(3)</sup>	\$ 1.16	\$ 0.94	\$ 0.69
– diluted <sup>(3)</sup>	\$ 1.16	\$ 0.93	\$ 0.68
Cash flows from operating activities	\$ 4,284	\$ 3,432	\$ 2,868
Adjusted funds flow <sup>(2)</sup>	\$ 4,530	\$ 4,186	\$ 3,138
Per common share			
– basic <sup>(3)</sup>	\$ 2.16	\$ 1.99	\$ 1.47
– diluted <sup>(3)</sup>	\$ 2.15	\$ 1.97	\$ 1.45
Cash flows used in investing activities	\$ 1,312	\$ 10,414	\$ 1,392
Net capital expenditures <sup>(4)</sup>	\$ 1,303	\$ 10,348	\$ 1,113
Abandonment expenditures	\$ 188	\$ 151	\$ 162

(1) Further details related to product sales are disclosed in note 15 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.

(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. 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 2025 were \$2,458 million compared with \$987 million for the first quarter of 2024 and \$1,138 million for the fourth quarter of 2024. Net earnings for the first quarter of 2025 included non-operating income, net of tax, of \$22 million compared with non-operating losses of \$487 million for the first quarter of 2024 and non-operating losses of \$839 million for the fourth quarter of 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the gain from investments, and a recoverability charge related to the increase in estimate of the future abandonment costs for the Ninian field in the North Sea in the fourth quarter of 2024. Excluding these items, adjusted net earnings from operations for the first quarter of 2025 were \$2,436 million compared with \$1,474 million for the first quarter of 2024 and \$1,977 million for the fourth quarter of 2024.

The increase in net earnings and adjusted net earnings from operations for the first quarter of 2025 from the first quarter of 2024 primarily reflected:

- higher sales volumes and realized SCO sales price<sup>(2)</sup> in the Oil Sands Mining and Upgrading segment; and
- higher crude oil and NGLs sales volumes and realized pricing<sup>(2)</sup> in the North America Exploration and Production segment.

The increase in net earnings and adjusted net earnings from operations for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected:

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

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of this MD&A and in note 1 to the financial statements.

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

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

## **Cash Flows from Operating Activities and Adjusted Funds Flow**

Cash flows from operating activities for the first quarter of 2025 were \$4,284 million compared with \$2,868 million for the first quarter of 2024, and \$3,432 million for the fourth quarter of 2024. 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 net changes in non-cash working capital.

Adjusted funds flow for the first quarter of 2025 was \$4,530 million compared with \$3,138 million for the first quarter of 2024, and \$4,186 million for the fourth quarter of 2024. 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, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, accrued interest on Petroleum Revenue Tax ("PRT") recoveries, and prepaid cost of service tolls.

## **Production Volumes**

Crude oil and NGLs production before royalties for the first quarter of 2025 of 1,173,804 bbl/d increased 20% from 975,668 bbl/d for the first quarter of 2024 and increased 8% from 1,090,002 bbl/d for the fourth quarter of 2024. Natural gas production before royalties for the first quarter of 2025 of 2,451 MMcf/d increased 14% from 2,147 MMcf/d for the first quarter of 2024 and increased 7% from 2,283 MMcf/d for the fourth quarter of 2024. Total production before royalties for the first quarter of 2025 of 1,582,348 BOE/d increased 19% from 1,333,502 BOE/d for the first quarter of 2024 and increased 8% from 1,470,428 BOE/d for the fourth quarter of 2024. 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 averaged \$79.85 per bbl for the first quarter of 2025, an increase of 14% from \$70.01 per bbl for the first quarter of 2024 and an increase of 6% from \$75.22 per bbl for the fourth quarter of 2024. The realized natural gas price increased 23% to average \$3.13 per Mcf for the first quarter of 2025 from \$2.55 per Mcf for the first quarter of 2024 and increased 55% from \$2.02 per Mcf for the fourth quarter of 2024. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price increased 8% to average \$95.52 per bbl for the first quarter of 2025 from \$88.84 per bbl for the first quarter of 2024 and was comparable with \$95.08 per bbl for the fourth quarter of 2024. The Company's realized product pricing is reflective of the 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<sup>(1)</sup> averaged \$15.74 per bbl for the first quarter of 2025, a decrease of 6% from \$16.66 per bbl for the first quarter of 2024 and an increase of 20% from \$13.15 per bbl for the fourth quarter of 2024. Natural gas production expense<sup>(1)</sup> averaged \$1.20 per Mcf for the first quarter of 2025, a decrease of 8% from \$1.30 per Mcf for the first quarter of 2024 and an increase of 7% from \$1.12 per Mcf for the fourth quarter of 2024. In the Oil Sands Mining and Upgrading segment, production expense<sup>(1)</sup> averaged \$21.88 per bbl for the first quarter of 2025, a decrease of 12% from \$24.85 per bbl for the first quarter of 2024 and an increase of 4% from \$20.97 per bbl for the fourth quarter of 2024. 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.

<sup>(1)</sup> 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 2025	Dec 31 2024	Sep 30 2024	Jun 30 2024
Product sales <sup>(1)</sup>	\$ 12,712	\$ 11,064	\$ 10,401	\$ 10,622
Crude oil and NGLs	\$ 11,732	\$ 10,381	\$ 9,943	\$ 10,084
Natural gas	\$ 716	\$ 451	\$ 257	\$ 331
Net earnings	\$ 2,458	\$ 1,138	\$ 2,266	\$ 1,715
Net earnings per common share				
– basic	\$ 1.17	\$ 0.54	\$ 1.07	\$ 0.80
– diluted	\$ 1.17	\$ 0.54	\$ 1.06	\$ 0.80

  

(\$ millions, except per common share amounts)	Mar 31 2024	Dec 31 2023	Sep 30 2023	Jun 30 2023
Product sales <sup>(1)</sup>	\$ 9,422	\$ 10,679	\$ 11,762	\$ 8,846
Crude oil and NGLs	\$ 8,676	\$ 9,829	\$ 10,944	\$ 8,115
Natural gas	\$ 529	\$ 603	\$ 599	\$ 522
Net earnings	\$ 987	\$ 2,627	\$ 2,344	\$ 1,463
Net earnings per common share <sup>(2)</sup>				
– basic	\$ 0.46	\$ 1.22	\$ 1.08	\$ 0.67
– diluted	\$ 0.46	\$ 1.21	\$ 1.06	\$ 0.66

(1) Further details related to product sales for the three months ended March 31, 2025 and 2024 are disclosed in note 15 to the financial statements.

(2) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of this MD&A and in note 1 to the financial statements.

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

- **Crude oil pricing** – Fluctuations in 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 the conflicts in the Middle East and in Ukraine, and economic impacts of escalating trade tensions) on worldwide benchmark pricing, the impact of shale oil production in North America, the impact of the start-up of the Trans Mountain Expansion ("TMX") pipeline in the second quarter of 2024, 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** – Fluctuations in both the demand for natural gas and inventory storage levels, the impact of 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 Kirby and Jackfish, fluctuations in production due to the cyclic nature of Primrose, fluctuations in the Company's drilling program in the North America Exploration and Production segment, natural field decline rates, the impact of turnarounds and pitstops in the Oil Sands Mining and Upgrading segment, the impact and timing of acquisitions, including the acquisition of working interests in AOSP and Duvernay assets in the fourth quarter of 2024, wildfires, and a third-party pipeline outage in 2023 in the North America Exploration and Production segment. 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 the North America Exploration and Production segment, the impact and timing of acquisitions, including the acquisition of a working interest in the Duvernay assets in the fourth quarter of 2024, natural field decline rates, the impact of seasonal conditions, wildfires, and a third-party pipeline outage in 2023 in the North America Exploration and Production segment.
- **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, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, 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, timing of acquisitions, 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, a recoverability charge at December 31, 2024 and December 31, 2023 relating to the increase in estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea, and a recoverability charge at June 30, 2024 relating to the notice to withdraw from Block 11B/12B in South Africa.
- **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 PRT recoveries.
- **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.

## BUSINESS ENVIRONMENT

Global crude oil benchmark pricing remained stable throughout the first quarter of 2025. However, mounting concerns over global crude oil demand growth outlooks and higher supply, fuelled by escalating trade tensions and an increased risk of an economic downturn, impacted pricing at the outset of the second quarter. Natural gas benchmark pricing recovered in the first quarter of 2025 following cold weather conditions in the US, increasing heating demand and storage draws. In Canada, the anticipated start-up of LNG Canada in the third quarter of 2025 will provide additional market egress and is expected to support AECO benchmark pricing.

In the first quarter of 2025, the US government announced tariffs on certain Canadian goods with countermeasures subsequently announced by the Canadian government. These trade measures have created market volatility which may continue to affect pricing received for the Company's products, increase the cost or reduce the availability of products in the Company's supply chain, and introduce additional foreign currency volatility. As of the date of this MD&A, the duration and impact of these trade actions remains uncertain, and tariffs are anticipated to evolve. The Company will continue to assess the impacts of any proposed or implemented tariffs on its business, financial condition and results.

### Liquidity

As at March 31, 2025, the Company had undrawn revolving bank credit facilities of \$4,965 million. Including cash and cash equivalents, the Company had approximately \$5,058 million in liquidity<sup>(1)</sup>. 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.

### Benchmark Commodity Prices

(Average for the period)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
WTI benchmark price (US\$/bbl)	\$ 71.42	\$ 70.27	\$ 76.97
Dated Brent benchmark price (US\$/bbl)	\$ 75.68	\$ 74.69	\$ 83.23
WCS Heavy Differential from WTI (US\$/bbl)	\$ 12.66	\$ 12.55	\$ 19.34
SCO price (US\$/bbl)	\$ 69.07	\$ 71.13	\$ 69.43
Condensate benchmark price (US\$/bbl)	\$ 69.89	\$ 70.66	\$ 72.79
NYMEX benchmark price (US\$/MMBtu)	\$ 3.66	\$ 2.79	\$ 2.24
AECO benchmark price (C\$/GJ)	\$ 1.92	\$ 1.38	\$ 1.94
US/Canadian dollar average exchange rate (US\$)	\$ 0.6969	\$ 0.7151	\$ 0.7415

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

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 resulting in product revenues being impacted by changes in Canadian dollar sales prices relative to the US dollar benchmark prices.

Crude oil sales contracts in North America are typically based on WTI benchmark pricing. WTI averaged US\$71.42 per bbl for the first quarter of 2025, a decrease of 7% from US\$76.97 per bbl for the first quarter of 2024 and comparable with US\$70.27 per bbl for the fourth quarter of 2024.

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US\$75.68 per bbl for the first quarter of 2025, a decrease of 9% from US\$83.23 per bbl for the first quarter of 2024 and comparable with US\$74.69 per bbl for the fourth quarter of 2024.

The decrease in WTI and Brent benchmark pricing for the first quarter of 2025 from the first quarter of 2024 reflected weaker global demand growth outlooks amid escalating trade tensions, combined with concerns of supply growth from non-OPEC+ producers.

The WCS Heavy Differential averaged US\$12.66 per bbl for the first quarter of 2025, compared with US\$19.34 per bbl for the first quarter of 2024 and US\$12.55 per bbl for the fourth quarter of 2024. The narrowing of the WCS Heavy Differential for the first quarter of 2025 from the first quarter of 2024 primarily reflected the start-up of the TMX pipeline in the second quarter of 2024, combined with stronger US Gulf Coast heavy oil pricing.

The SCO price averaged US\$69.07 per bbl for the first quarter of 2025, comparable with US\$69.43 per bbl for the first quarter of 2024 and a decrease of 3% from US\$71.13 per bbl for the fourth quarter of 2024. The SCO differential weakened in the first quarter of 2025 relative to the fourth quarter of 2024, driven in part by production levels in the Western Canadian Sedimentary Basin ("WCSB").

NYMEX benchmark pricing averaged US\$3.66 per MMBtu for the first quarter of 2025, an increase of 63% from US\$2.24 per MMBtu for the first quarter of 2024 and an increase of 31% from US\$2.79 per MMBtu for the fourth quarter of 2024. The increase in NYMEX benchmark pricing for the first quarter of 2025 from the comparable periods in 2024 primarily reflected cold US weather conditions in the first quarter of 2025 resulting in increased heating demand and storage draws, combined with higher LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged \$1.92 per GJ for the first quarter of 2025, comparable with \$1.94 per GJ for the first quarter of 2024 and an increase of 39% from \$1.38 per GJ for the fourth quarter of 2024. The increase in AECO benchmark pricing for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected stronger NYMEX benchmark pricing, combined with increased exports out of the WCSB. AECO benchmark pricing also reflects the anticipated start-up of LNG Canada in the third quarter of 2025.

## DAILY PRODUCTION, before royalties

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	<b>561,238</b>	531,960	505,636
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	<b>595,116</b>	534,631	445,209
International – Exploration and Production			
North Sea	<b>11,507</b>	11,467	12,433
Offshore Africa	<b>5,943</b>	11,944	12,390
Total International <sup>(2)</sup>	<b>17,450</b>	23,411	24,823
Total Crude oil and NGLs	<b>1,173,804</b>	1,090,002	975,668
<b>Natural gas (MMcf/d) <sup>(3)</sup></b>			
North America	<b>2,436</b>	2,273	2,135
International			
North Sea	<b>4</b>	4	1
Offshore Africa	<b>11</b>	6	11
Total International	<b>15</b>	10	12
Total Natural gas	<b>2,451</b>	2,283	2,147
Total Barrels of oil equivalent (BOE/d)	<b>1,582,348</b>	1,470,428	1,333,502
<b>Product mix</b>			
Light and medium crude oil and NGLs	<b>10%</b>	10%	11%
Pelican Lake heavy crude oil	<b>3%</b>	3%	3%
Primary heavy crude oil	<b>5%</b>	6%	6%
Bitumen (thermal oil)	<b>18%</b>	19%	20%
Synthetic crude oil <sup>(1)</sup>	<b>38%</b>	36%	33%
Natural gas	<b>26%</b>	26%	27%
<b>Percentage of product sales <sup>(1) (4) (5)</sup></b>			
Crude oil and NGLs	<b>94%</b>	96%	94%
Natural gas	<b>6%</b>	4%	6%

(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 in this MD&A.

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

## DAILY PRODUCTION, net of royalties

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	<b>455,307</b>	425,682	413,752
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	<b>480,227</b>	432,701	370,837
International – Exploration and Production			
North Sea	<b>11,493</b>	11,441	12,406
Offshore Africa	<b>5,685</b>	11,364	11,755
Total International	<b>17,178</b>	22,805	24,161
Total Crude oil and NGLs	<b>952,712</b>	881,188	808,750
<b>Natural gas (MMcf/d)</b>			
North America	<b>2,348</b>	2,223	2,049
International			
North Sea	<b>4</b>	4	1
Offshore Africa	<b>11</b>	6	11
Total International	<b>15</b>	10	12
Total Natural gas	<b>2,363</b>	2,233	2,061
Total Barrels of oil equivalent (BOE/d)	<b>1,346,536</b>	1,253,347	1,152,258

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

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 2025 averaged 1,173,804 bbl/d, an increase of 20% from 975,668 bbl/d for the first quarter of 2024 and an increase of 8% from 1,090,002 bbl/d for the fourth quarter of 2024. The increase in crude oil and NGLs production before royalties for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, combined with strong utilization in the Oil Sands Mining and Upgrading segment and thermal oil pad additions in the North America Exploration and Production segment.

Annual crude oil and NGLs production for 2025 is targeted to average between 1,106,000 bbl/d and 1,142,000 bbl/d. Production targets constitute forward-looking statements. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Natural gas production before royalties for the first quarter of 2025 averaged 2,451 MMcf/d, an increase of 14% from 2,147 MMcf/d for the first quarter of 2024 and an increase of 7% from 2,283 MMcf/d for the fourth quarter of 2024. The increase in natural gas production before royalties for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024 and strong drilling results.

Annual natural gas production for 2025 is targeted to average between 2,425 MMcf/d and 2,480 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 2025 of 561,238 bbl/d increased 11% from 505,636 bbl/d for the first quarter of 2024 and increased 6% from 531,960 bbl/d for the fourth quarter of 2024. The increase in North America crude oil and NGLs production for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, thermal oil pad additions at Primrose, and strong conventional drilling results.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 284,706 bbl/d for the first quarter of 2025, an increase of 6% from 268,155 bbl/d for the first quarter of 2024 and an increase of 3% from 276,231 bbl/d for the fourth quarter of 2024. The increase in thermal in situ production in the first quarter of 2025 from the comparable periods in 2024 primarily reflected pad additions at Primrose, partially offset by natural field declines.

Pelican Lake heavy crude oil production before royalties for the first quarter of 2025 averaged 43,175 bbl/d, a decrease of 4% from 45,145 bbl/d for the first quarter of 2024 reflecting Pelican Lake's long life low decline, and comparable with 44,035 bbl/d for the fourth quarter of 2024.

Natural gas production before royalties averaged 2,436 MMcf/d for the first quarter of 2025, an increase of 14% from 2,135 MMcf/d for the first quarter of 2024 and an increase of 7% from 2,273 MMcf/d for the fourth quarter of 2024. The increase in natural gas production for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024 and strong drilling results.

## **North America – Oil Sands Mining and Upgrading**

Record SCO production before royalties for the first quarter of 2025 averaged 595,116 bbl/d, an increase of 34% from 445,209 bbl/d for the first quarter of 2024 and an increase of 11% from 534,631 bbl/d for the fourth quarter of 2024. The increase in SCO production for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024, combined with strong performance and utilization following the completion of the reliability enhancement project at Horizon and debottleneck project at the non-operated Scotford Upgrader.

## **International – Exploration and Production**

International crude oil and NGLs production before royalties for the first quarter of 2025 averaged 17,450 bbl/d, a decrease of 30% from 24,823 bbl/d for the first quarter of 2024 and a decrease of 25% from 23,411 bbl/d for the fourth quarter of 2024. The decrease in International crude oil and NGLs production for the first quarter of 2025 from the comparable periods in 2024 primarily reflected suspended production at Baobab in Offshore Africa due to planned maintenance on its floating production storage and offloading vessel ("FPSO") which commenced in the first quarter of 2025 and is expected to return to service in the second quarter of 2026.

## OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
Realized price <sup>(2)</sup>	\$ 79.85	\$ 75.22	\$ 70.01
Transportation <sup>(3)</sup>	6.40	6.08	4.63
Realized price, net of transportation <sup>(2)</sup>	73.45	69.14	65.38
Royalties <sup>(4)</sup>	14.36	14.77	12.09
Production expense <sup>(5)</sup>	15.74	13.15	16.66
Netback <sup>(2)</sup>	\$ 43.35	\$ 41.22	\$ 36.63
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
Realized price <sup>(6)</sup>	\$ 3.13	\$ 2.02	\$ 2.55
Transportation <sup>(3)</sup>	0.63	0.59	0.64
Realized price, net of transportation	2.50	1.43	1.91
Royalties <sup>(4)</sup>	0.11	0.04	0.10
Production expense <sup>(5)</sup>	1.20	1.12	1.30
Netback <sup>(7)</sup>	\$ 1.19	\$ 0.27	\$ 0.51
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>			
Realized price <sup>(2)</sup>	\$ 54.95	\$ 49.54	\$ 47.60
Transportation <sup>(3)</sup>	5.34	5.06	4.31
Realized price, net of transportation <sup>(2)</sup>	49.61	44.48	43.29
Royalties <sup>(4)</sup>	8.76	8.85	7.39
Production expense <sup>(5)</sup>	12.23	10.53	13.03
Netback <sup>(2)</sup>	\$ 28.62	\$ 25.10	\$ 22.87

(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 transportation expense divided by respective sales volumes.

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

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

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

(7) Natural gas netbacks exclude NGLs netbacks derived from the Company's liquids-rich natural gas plays.

## REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America <sup>(2)</sup>	\$ 78.56	\$ 74.46	\$ 68.14
International average <sup>(3)</sup>	\$ 107.04	\$ 96.36	\$ 112.94
North Sea <sup>(3)</sup>	\$ 107.57	\$ 103.80	\$ 113.75
Offshore Africa <sup>(3)</sup>	\$ 106.30	\$ 86.93	\$ 111.59
Crude oil and NGLs average <sup>(2)</sup>	\$ 79.85	\$ 75.22	\$ 70.01
<b>Natural gas (\$/Mcf) <sup>(1) (3)</sup></b>			
North America	\$ 3.06	\$ 1.98	\$ 2.50
International average	\$ 14.46	\$ 11.28	\$ 12.13
North Sea	\$ 16.43	\$ 8.87	\$ 11.48
Offshore Africa	\$ 13.65	\$ 12.62	\$ 12.22
Natural gas average	\$ 3.13	\$ 2.02	\$ 2.55
Average (\$/BOE) <sup>(1) (2)</sup>	\$ 54.95	\$ 49.54	\$ 47.60

(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 averaged \$78.56 per bbl for the first quarter of 2025, an increase of 15% from \$68.14 per bbl for the first quarter of 2024 and an increase of 6% from \$74.46 per bbl for the fourth quarter of 2024. The increase in North America realized crude oil and NGLs prices per bbl for the first quarter of 2025 from the comparable periods in 2024 primarily reflected fluctuations in the WCS Heavy Differential and in foreign exchange. The Company continues to focus on its crude oil blending marketing strategy and in the first quarter of 2025 contributed approximately 223,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 22% to average \$3.06 per Mcf for the first quarter of 2025 from \$2.50 per Mcf for the first quarter of 2024 and increased 55% from \$1.98 per Mcf for the fourth quarter of 2024. The increase in North America realized natural gas prices per Mcf for the first quarter of 2025 from the first quarter of 2024 primarily reflected higher export pricing. The increase for the first quarter of 2025 from the fourth quarter of 2024 reflected higher AECO benchmark and export pricing.

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

(Quarterly average)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Wellhead Price <sup>(1)</sup></b>			
Light and medium crude oil and NGLs (\$/bbl)	\$ 76.47	\$ 68.63	\$ 66.68
Pelican Lake heavy crude oil (\$/bbl)	\$ 83.57	\$ 79.88	\$ 74.69
Primary heavy crude oil (\$/bbl)	\$ 81.76	\$ 78.34	\$ 74.37
Bitumen (thermal oil) (\$/bbl)	\$ 77.96	\$ 75.11	\$ 65.83
Natural gas (\$/Mcf)	\$ 3.06	\$ 1.98	\$ 2.50

(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 5% to average \$107.04 per bbl for the first quarter of 2025 from \$112.94 per bbl for the first quarter of 2024 and increased 11% from \$96.36 per bbl for the fourth quarter of 2024. 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 Brent benchmark prices and foreign exchange rates at the time of lifting.

## ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America	\$ 14.94	\$ 15.22	\$ 12.52
International average	\$ 1.99	\$ 1.99	\$ 2.29
North Sea	\$ 0.14	\$ 0.23	\$ 0.24
Offshore Africa	\$ 4.61	\$ 4.22	\$ 5.72
Crude oil and NGLs average	\$ 14.36	\$ 14.77	\$ 12.09
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
North America	\$ 0.11	\$ 0.04	\$ 0.10
Offshore Africa	\$ 0.63	\$ 0.58	\$ 0.56
Natural gas average	\$ 0.11	\$ 0.04	\$ 0.10
Average (\$/BOE) <sup>(1)</sup>	\$ 8.76	\$ 8.85	\$ 7.39

(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 2025 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 <sup>(1)</sup> averaged approximately 19% of product sales for the first quarter of 2025 compared with 18% for the first quarter of 2024 and 20% for the fourth quarter of 2024. The fluctuations in royalty rates for the first quarter of 2025 from the comparable periods in 2024 primarily reflected prevailing benchmark pricing and fluctuations in the WCS Heavy Differential.

Natural gas royalty rates averaged approximately 4% of product sales for the first quarter of 2025 compared with 4% for the first quarter of 2024 and 2% for the fourth quarter of 2024. The fluctuations in royalty rates for the first quarter of 2025 from the comparable periods in 2024 primarily reflected benchmark pricing.

### Offshore Africa

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

Royalty rates as a percentage of product sales averaged approximately 4% for the first quarter of 2025 compared with 5% of product sales for the first quarter of 2024 and 5% for the fourth quarter of 2024. 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 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America	\$ 12.65	\$ 10.83	\$ 14.72
International average	\$ 80.63	\$ 77.66	\$ 61.32
North Sea	\$ 117.56	\$ 118.91	\$ 85.58
Offshore Africa	\$ 28.26	\$ 25.34	\$ 20.70
Crude oil and NGLs average	\$ 15.74	\$ 13.15	\$ 16.66
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
North America	\$ 1.16	\$ 1.09	\$ 1.27
International average	\$ 7.60	\$ 7.81	\$ 5.71
North Sea	\$ 10.52	\$ 9.38	\$ 8.66
Offshore Africa	\$ 6.42	\$ 6.94	\$ 5.33
Natural gas average	\$ 1.20	\$ 1.12	\$ 1.30
Average (\$/BOE) <sup>(1)</sup>	\$ 12.23	\$ 10.53	\$ 13.03

(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 2025 of \$12.65 per bbl decreased 14% from \$14.72 per bbl for the first quarter of 2024 and increased 17% from \$10.83 per bbl for the fourth quarter of 2024. The decrease in crude oil and NGLs production expense per bbl for the first quarter of 2025 from the first quarter of 2024 primarily reflected lower energy costs, combined with higher production volumes. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected increased energy and seasonal service costs in the first quarter of 2025, partially offset by higher production volumes.

North America natural gas production expense for the first quarter of 2025 of \$1.16 per Mcf decreased 9% from \$1.27 per Mcf for the first quarter of 2024 and increased 6% from \$1.09 per Mcf for the fourth quarter of 2024. The decrease in natural gas production expense per Mcf for the first quarter of 2025 from the first quarter of 2024 primarily reflected higher production volumes. The increase in natural gas production expense per Mcf for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected seasonal service costs, partially offset by higher production volumes.

### International

International crude oil and NGLs production expense for the first quarter of 2025 of \$80.63 per bbl increased 31% from \$61.32 per bbl for the first quarter of 2024 and increased 4% from \$77.66 per bbl for the fourth quarter of 2024. The increase in crude oil and NGLs production expense per bbl for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the timing of liftings from various fields that have different cost structures and the impact of foreign exchange.

## ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

(\$ millions, except per BOE amounts)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
North America	\$ 1,092	\$ 1,010	\$ 941
North Sea	40	221	17
Offshore Africa	59	46	47
Depletion, depreciation and amortization	\$ 1,191	\$ 1,277	\$ 1,005
Less: Recoverability charge <sup>(1)</sup>	—	160	—
Adjusted depletion, depreciation and amortization <sup>(2)</sup>	\$ 1,191	\$ 1,117	\$ 1,005
\$/BOE <sup>(3)</sup>	\$ 13.27	\$ 13.01	\$ 12.64

(1) As at December 31, 2024, as a result of refined project scope and cost estimates associated with abandonment activities, the Company recognized a recoverability charge of \$160 million in depletion, depreciation and amortization expense related to an increase in its estimate of future abandonment costs for the Ninian field in the North Sea.

(2) This is a non-GAAP financial measure used to calculate depletion, depreciation and amortization, less the impact of charges that are not related to current period normal course depletion, depreciation and amortization expense such as asset recoverability charges that are not related to current period production. 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 an indication of the Company's performance.

(3) This is a non-GAAP ratio calculated as adjusted depletion, depreciation and amortization expense 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 2025 averaged \$13.27 per BOE, an increase of 5% from \$12.64 per BOE for the first quarter of 2024 and comparable with \$13.01 per BOE for the fourth quarter of 2024. The increase in adjusted depletion, depreciation and amortization expense per BOE for the first quarter of 2025 from the first quarter of 2024 primarily reflected the impact of changes in North America depletion rates due to changes in reserve estimates at December 31, 2024, combined with a higher depletable base due to asset additions, partially offset by higher sales volumes.

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 2025	Dec 31 2024	Mar 31 2024
North America	\$ 53	\$ 58	\$ 58
North Sea	14	17	16
Offshore Africa	2	3	2
Asset retirement obligation accretion	\$ 69	\$ 78	\$ 76
\$/BOE <sup>(1)</sup>	\$ 0.77	\$ 0.89	\$ 0.95

(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 for the first quarter of 2025 averaged \$0.77 per BOE, a decrease of 19% from \$0.95 per BOE for the first quarter of 2024 and a decrease of 13% from \$0.89 per BOE for the fourth quarter of 2024. The decrease in asset retirement obligation accretion expense per BOE for the first quarter of 2025 from the comparable periods in 2024 reflected the impact of changes in discount rate estimate revisions at December 31, 2024, combined with higher sales volumes in the first quarter of 2025, partially offset by revisions in cost and timing estimates at December 31, 2024.

## 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 with record SCO production averaging 595,116 bbl/d in the first quarter of 2025.

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

(\$/bbl)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Realized SCO sales price <sup>(1)</sup>	\$ 95.52	\$ 95.08	\$ 88.84
Bitumen value for royalty purposes <sup>(2)</sup>	\$ 73.72	\$ 69.35	\$ 63.51
Bitumen royalties <sup>(3)</sup>	\$ 18.22	\$ 17.20	\$ 14.28
Transportation <sup>(4)</sup>	\$ 3.21	\$ 3.60	\$ 1.67

(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.

(4) Calculated as transportation expense divided by sales volumes.

The realized SCO sales price averaged \$95.52 per bbl for the first quarter of 2025, an increase of 8% from \$88.84 per bbl for the first quarter of 2024 and comparable with \$95.08 per bbl for the fourth quarter of 2024. The increase in realized SCO sales price per bbl for the first quarter of 2025 from the first quarter of 2024 primarily reflected a strengthening of the SCO differential as a result of additional egress following the start-up of the TMX pipeline in the second quarter of 2024, partially offset by lower WTI benchmark pricing.

The fluctuations in bitumen royalties per bbl in any particular period reflect prevailing bitumen pricing for royalty purposes, and the impact of sliding scale royalty rates. The increase in bitumen royalties per bbl for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the increase in average bitumen pricing for royalty purposes.

Transportation expense averaged \$3.21 per bbl for the first quarter of 2025, an increase of 92% from \$1.67 per bbl for the first quarter of 2024 and a decrease of 11% from \$3.60 per bbl for the fourth quarter of 2024. The increase in transportation expense per bbl for the first quarter of 2025 from the first quarter of 2024 primarily reflected new volumes shipped on the TMX pipeline beginning in the second quarter of 2024. The decrease for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected lower volumes shipped to the US Gulf Coast, partially offset by higher volumes shipped on the TMX pipeline.

## PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Production expense, excluding natural gas costs	\$ 1,135	\$ 991	\$ 976
Natural gas costs	50	28	50
Production expense	\$ 1,185	\$ 1,019	\$ 1,026

(\$/bbl)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Production expense, excluding natural gas costs <sup>(1)</sup>	\$ 20.95	\$ 20.39	\$ 23.64
Natural gas costs <sup>(2)</sup>	0.93	0.58	1.21
Production expense <sup>(3)</sup>	\$ 21.88	\$ 20.97	\$ 24.85
Sales volumes (bbl/d)	602,048	528,248	453,794

(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.

The Company incurred production expense of \$1,185 million for the first quarter of 2025, an increase of 15% from \$1,026 million for the first quarter of 2024 and an increase of 16% from \$1,019 million for the fourth quarter of 2024. The increase in production expense for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the acquisition in December 2024.

Production expense for the first quarter of 2025 averaged \$21.88 per bbl, a decrease of 12% from \$24.85 per bbl for the first quarter of 2024 and an increase of 4% from \$20.97 per bbl for the fourth quarter of 2024. The decrease in production expense per bbl for the first quarter of 2025 from the first quarter of 2024 primarily reflected higher production volumes. The increase in production expense per bbl for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected higher energy and seasonal service costs, partially offset by higher production volumes.

## DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Depletion, depreciation and amortization	\$ 675	\$ 621	\$ 524
\$/bbl <sup>(1)</sup>	\$ 12.45	\$ 12.76	\$ 12.70

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

Depletion, depreciation and amortization expense for the first quarter of 2025 of \$12.45 per bbl was comparable with \$12.70 per bbl for the first quarter of 2024 and \$12.76 per bbl for the fourth quarter of 2024.

## ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

(\$ millions, except per bbl amounts)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Asset retirement obligation accretion	\$ 22	\$ 20	\$ 21
\$/bbl <sup>(1)</sup>	\$ 0.40	\$ 0.44	\$ 0.51

(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 for the first quarter of 2025 of \$0.40 per bbl decreased 22% from \$0.51 per bbl for the first quarter of 2024 and decreased 9% from \$0.44 per bbl for the fourth quarter of 2024. The decrease in asset retirement obligation accretion expense per bbl for the first quarter of 2025 from the comparable periods in 2024 primarily reflected the impact of higher sales volumes in the first quarter of 2025.

## MIDSTREAM AND REFINING

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Product sales			
Midstream activities	\$ 22	\$ 21	\$ 20
NWRP, refined product sales and other	221	193	214
Segmented revenue	243	214	234
Less:			
NWRP, refining toll	68	65	74
Midstream activities	5	5	5
Production expense	73	70	79
NWRP, feedstock costs	172	160	153
NWRP, transportation expense	4	4	5
Depreciation	4	3	4
Segmented loss	\$ (10)	\$ (23)	\$ (7)

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 North West Redwater Partnership ("NWRP").

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery processes approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), 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 2025, production of ultra-low sulphur diesel and other refined products averaged 83,863 BOE/d (20,966 BOE/d to the Company) (three months ended December 31, 2024 – 77,742 BOE/d; 19,436 BOE/d to the Company; three months ended March 31, 2024 – 78,569 BOE/d; 19,642 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at March 31, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$528 million (December 31, 2024 – \$509 million). For the three months ended March 31, 2025, the Company's unrecognized share of the equity loss was \$19 million (three months ended March 31, 2024 – recovery of unrecognized equity losses of \$4 million).

## ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Administration expense	\$ 152	\$ 127	\$ 126
\$/BOE <sup>(1)</sup>	\$ 1.06	\$ 0.95	\$ 1.04
Sales volumes (BOE/d) <sup>(2)</sup>	1,599,487	1,460,909	1,327,762

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

(2) Total Company sales volumes.

Administration expense for the first quarter of 2025 averaged \$1.06 per BOE, comparable with \$1.04 per BOE for the first quarter of 2024 and an increase of 12% from \$0.95 per BOE for the fourth quarter of 2024. The increase in administration expense per BOE for the first quarter of 2025 from the fourth quarter of 2024 primarily reflected higher personnel costs, partially offset by higher sales volumes.

## SHARE-BASED COMPENSATION

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Share-based compensation expense	\$ 26	\$ 44	\$ 294

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 with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognized \$26 million of share-based compensation expense for the three months ended March 31, 2025, 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

(\$ millions, except effective interest rate)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Interest and other financing expense	\$ 258	\$ 142	\$ 138
Less: Interest (income) and other expense <sup>(1)</sup>	(6)	(47)	(22)
Interest expense on long-term debt and lease liabilities <sup>(1)</sup>	\$ 264	\$ 189	\$ 160
Average current and long-term debt <sup>(2)</sup>	\$ 19,147	\$ 13,285	\$ 11,595
Average lease liabilities <sup>(2)</sup>	1,422	1,457	1,542
Average long-term debt and lease liabilities <sup>(2)</sup>	\$ 20,569	\$ 14,742	\$ 13,137
Average effective interest rate <sup>(3) (4)</sup>	5.0%	5.0%	4.8%
Interest and other financing expense (\$/BOE) <sup>(5)</sup>	\$ 1.79	\$ 1.06	\$ 1.15
Sales volumes (BOE/d) <sup>(6)</sup>	1,599,487	1,460,909	1,327,762

(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 expense 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 for the first quarter of 2025 increased 56% to \$1.79 per BOE from \$1.15 per BOE for the first quarter of 2024 and increased 69% from \$1.06 per BOE for the fourth quarter of 2024. The increase in interest and other financing expense per BOE for the first quarter of 2025 from the comparable periods in 2024 primarily reflected higher average debt levels, partially offset by higher sales volumes.

The Company's average effective interest rate for the first quarter of 2025 averaged 5.0%, an increase from the first quarter of 2024, reflecting higher floating rate debt held in the first quarter of 2025, combined with fixed rate debt issuances in the fourth quarter of 2024.

## RISK MANAGEMENT ACTIVITIES

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

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Foreign currency forward contracts	\$ (20)	\$ 144	\$ 26
Foreign currency put options <sup>(1)</sup>	(4)	—	—
Natural gas financial instruments <sup>(2) (3) (4)</sup>	(3)	2	(1)
Net realized (gain) loss	(27)	146	25
Foreign currency forward contracts	14	(2)	9
Foreign currency put options <sup>(1)</sup>	(2)	—	—
Natural gas financial instruments <sup>(2) (3) (4)</sup>	(9)	(2)	4
Net unrealized loss (gain)	3	(4)	13
Net (gain) loss	\$ (24)	\$ 142	\$ 38

(1) During 2025, the Company entered into foreign currency put options contracts. Further details are disclosed in note 13 to the financial statements.

(2) Certain commodity financial instruments were assumed in the acquisition of Painted Pony Energy Ltd. in the fourth quarter of 2020.

(3) In the fourth quarter of 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US\$1.47 AECO, and 25,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2025.

(4) In the fourth quarter of 2023, the Company entered into fixed price financial contracts to buy 50,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2024.

During the first quarter of 2025, net realized risk management gains were primarily related to the settlement of foreign currency forward contracts. The Company recorded a net unrealized loss of \$3 million (\$2 million after tax of \$1 million) on its risk management activities for the three months ended March 31, 2025 (three months ended December 31, 2024 – unrealized gain of \$4 million (\$3 million after tax of \$1 million); three months ended March 31, 2024 – unrealized loss of \$13 million (\$12 million after tax of \$1 million)).

Further details related to outstanding derivative financial instruments as at March 31, 2025 are disclosed in note 13 to the financial statements.

## FOREIGN EXCHANGE

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Net realized loss (gain)	\$ 242	\$ (62)	\$ (19)
Net unrealized (gain) loss	(285)	782	269
Net (gain) loss <sup>(1)</sup>	\$ (43)	\$ 720	\$ 250

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

The net realized foreign exchange loss for the first quarter of 2025 was primarily related to the repayment of US dollar debt. The net unrealized foreign exchange gain for the first quarter of 2025 was primarily related to the repayment of US dollar debt during the first quarter of 2025, combined with the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at March 31, 2025 was US\$0.6955 (December 31, 2024 – US\$0.6942, March 31, 2024 – US\$0.7390).

## INCOME TAXES

(\$ millions, except effective tax rates)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
North America <sup>(1)</sup>	\$ 569	\$ 261	\$ 412
North Sea	(26)	(11)	(5)
Offshore Africa	5	35	5
Current PRT – North Sea	(39)	(67)	(14)
Other taxes	2	3	3
Current income tax	511	221	401
Deferred corporate income tax	119	372	14
Deferred PRT – North Sea	9	(145)	6
Deferred income tax	128	227	20
Income tax	\$ 639	\$ 448	\$ 421
Earnings before taxes	\$ 3,097	\$ 1,586	\$ 1,408
Effective tax rate on net earnings <sup>(2)</sup>	21%	28%	30%

(\$ millions, except effective tax rates)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Income tax	\$ 639	\$ 448	\$ 421
Tax effect on non-operating items <sup>(3)</sup>	5	143	14
Current PRT – North Sea	39	67	14
Deferred PRT – North Sea	(9)	56	(6)
Other taxes	(2)	(3)	(3)
Effective tax on adjusted net earnings	\$ 672	\$ 711	\$ 440
Adjusted net earnings from operations <sup>(4)</sup>	\$ 2,436	\$ 1,977	\$ 1,474
Adjusted net earnings from operations, before taxes	\$ 3,108	\$ 2,688	\$ 1,914
Effective tax rate on adjusted net earnings from operations <sup>(5) (6)</sup>	22%	26%	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 income tax effect on PSUs, certain stock options, unrealized risk management, and a recoverability charge related to the increase in future abandonment costs for Ninian field in the North Sea in the fourth quarter of 2024.

(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 2025 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 and deferred corporate income tax and the current and deferred PRT in the North Sea for the first quarter of 2025 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities at the Company's platforms in the North Sea.

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

## NET CAPITAL EXPENDITURES <sup>(1) (2)</sup>

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Exploration and Production</b>			
<b>Exploration and Evaluation Assets</b>			
Net expenditures	\$ 19	\$ 9	\$ 69
Net property (dispositions) acquisitions <sup>(3)</sup>	(13)	330	—
Total Exploration and Evaluation Assets	6	339	69
<b>Property, Plant and Equipment</b>			
Net property acquisitions (dispositions) <sup>(3)</sup>	31	2,553	(3)
Well drilling, completion and equipping	536	472	413
Production and related facilities	390	341	255
Other	3	14	12
Total Property, Plant and Equipment	960	3,380	677
Total Exploration and Production	966	3,719	746
<b>Oil Sands Mining and Upgrading</b>			
Project costs	55	66	62
Sustaining capital	216	357	281
Turnaround costs	46	16	11
Net property acquisitions (dispositions) <sup>(3)</sup>	—	6,175	(2)
Other	2	1	1
Total Oil Sands Mining and Upgrading	319	6,615	353
<b>Midstream and Refining</b>	2	1	4
<b>Head Office</b>	16	13	10
<b>Net capital expenditures</b>	\$ 1,303	\$ 10,348	\$ 1,113
<b>Abandonment expenditures</b>	\$ 188	\$ 151	\$ 162
<b>By Segment</b>			
North America	\$ 836	\$ 3,632	\$ 701
North Sea	3	3	4
Offshore Africa	127	84	41
Oil Sands Mining and Upgrading	319	6,615	353
Midstream and Refining	2	1	4
Head Office	16	13	10
<b>Net capital expenditures</b>	\$ 1,303	\$ 10,348	\$ 1,113

(1) Net capital expenditures exclude the impact of lease assets, fair value and revaluation adjustments.

(2) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.

(3) Includes cash consideration paid of \$320 million for exploration and evaluation assets and \$2,553 million for property, plant and equipment within the North America Exploration and Production segment, and \$6,175 million for property, plant and equipment within the Oil Sands Mining and Upgrading segment acquired from Chevron in the fourth quarter of 2024.

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 were \$1,303 million for the first quarter of 2025 compared with \$1,113 million for the first quarter of 2024 and \$10,348 million for the fourth quarter of 2024.

In addition, the Company reported abandonment expenditures of \$188 million for the first quarter of 2025 compared with \$162 million for the first quarter of 2024 and \$151 million for the fourth quarter of 2024.

## 2025 Capital Budget

On January 9, 2025, the Company announced its 2025 operating capital budget<sup>(1)</sup> targeted at approximately \$6,015 million, which includes capital related to a number of acquisitions for which agreements between parties have been reached, with closings targeted in the first half of 2025, and subject to regulatory approvals and other customary closing conditions. With this capital, the Company is targeting near-term production growth in 2025 and mid- and long-term production and capacity growth in 2026 and beyond. In addition, the Company has approved approximately \$135 million of capital, consisting of \$90 million related to carbon capture and \$45 million related to a one-time office move scheduled to take place through 2026. The Company targets \$787 million in abandonment expenditures for 2025. Production for 2025 is targeted between 1,510 MBOE/d and 1,555 MBOE/d. On May 7, 2025, the 2025 total capital was reduced by \$100 million to \$6,050 million, excluding abandonment expenditures. Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns and the balancing of project risks and time horizons. The 2025 capital budget constitutes forward-looking statements and is based on net capital expenditures. Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

## Drilling Activity<sup>(1) (2)</sup>

	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
(number of net wells)			
Net successful crude oil wells <sup>(3)</sup>	74	100	61
Net successful natural gas wells	19	14	16
Dry wells	1	—	—
Total	94	114	77
Success rate	99%	100%	100%

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

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

## North America

During the first quarter of 2025, the Company drilled 19 net natural gas wells, 32 net primary heavy crude oil wells, 8 net Pelican Lake heavy crude oil wells, 18 net bitumen (thermal oil) wells and 17 net light crude oil wells.

## LIQUIDITY AND CAPITAL RESOURCES

	Mar 31 2025	Dec 31 2024	Mar 31 2024
(\$ millions, except ratios)			
Adjusted working capital <sup>(1)</sup>	\$ 20	\$ 174	\$ 774
Long-term debt, net <sup>(2)</sup>	\$ 17,335	\$ 18,688	\$ 10,273
Shareholders' equity	\$ 40,445	\$ 39,468	\$ 39,508
Debt to book capitalization <sup>(2)</sup>	30.0%	32.1%	20.6%
After-tax return on average capital employed <sup>(3)</sup>	15.3%	12.7%	15.6%

(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, 2025, 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 are 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, 2024. 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.

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

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 capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the first quarter of 2025, the Company extended its \$500 million revolving credit facility originally maturing February 2026 to June 2027.
  - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, 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 2023, 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 2025. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
  - During the first quarter of 2025, the Company repaid US\$600 million of 3.90% US dollar debt securities due February 2025.
  - In July 2023, 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 2025. 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, 2025, the Company had undrawn revolving bank credit facilities of \$4,965 million and a fully drawn non-revolving term credit facility of \$4,000 million. Including cash and cash equivalents, the Company had approximately \$5,058 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. As at March 31, 2025, the Company had \$566 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 \$17,335 million as at March 31, 2025 (December 31, 2024 – \$18,688 million), resulting in a debt to book capitalization ratio of 30.0% (December 31, 2024 – 32.1%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. 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, 2025, the Company was in compliance with this covenant.

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, 2025 are discussed in note 6 to the financial statements.

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 commodity put options is in addition to the above parameters.

As at March 31, 2025, 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 <sup>(1)</sup>	\$ 1,429	\$ 441	\$ 7,586	\$ 8,061
Other long-term liabilities <sup>(2)</sup>	\$ 274	\$ 153	\$ 378	\$ 620
Interest and other financing expense <sup>(3)</sup>	\$ 946	\$ 926	\$ 1,859	\$ 3,433

(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, \$255 million; one to less than two years, \$153 million; two to less than five years, \$378 million; and thereafter, \$620 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at March 31, 2025.

## Share Capital

As at March 31, 2025, there were 2,097,494,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 61,030,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at May 6, 2025, the Company had 2,093,276,000 common shares outstanding and 60,357,000 stock options outstanding.

On March 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to \$0.5875 per common share, beginning with the dividend paid on April 4, 2025.

On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to \$0.5625 per common share. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to \$0.525 per common share.

The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 10, 2025, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 178,738,237 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2025 and ending March 12, 2026.

For the three months ended March 31, 2025, the Company purchased 11,160,000 common shares at a weighted average price of \$43.66 per common share for a total cost, including tax, of \$492 million. Retained earnings were reduced by \$433 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2025, up to and including May 6, 2025, the Company purchased 4,500,000 common shares at a weighted average price of \$39.72 per common share for a total cost, including tax, of \$182 million.

## COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at March 31, 2025:

(\$ millions)	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases, and processing <sup>(1)</sup>	\$ 1,701	\$ 2,272	\$ 2,126	\$ 1,993	\$ 1,891	\$ 19,219
North West Redwater Partnership service toll <sup>(2)</sup>	\$ 104	\$ 118	\$ 98	\$ 100	\$ 98	\$ 4,054
Offshore vessels and equipment	\$ 28	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and power	\$ 35	\$ 29	\$ 29	\$ 28	\$ 27	\$ 216
Other	\$ 112	\$ 110	\$ 19	\$ 20	\$ 19	\$ 208

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the TMX pipeline reflects interim tolls approved by the Canada Energy Regulator in the fourth quarter of 2023, and is subject to change pending the approval of final tolls.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,977 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, 2024.

## **CONTROL ENVIRONMENT**

There have been no changes to internal control over financial reporting ("ICFR") during the three months ended March 31, 2025 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, and 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 impacts. 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.

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Net earnings	\$ 2,458	\$ 1,138	\$ 987
Share-based compensation, net of tax <sup>(1)</sup>	22	39	281
Unrealized risk management loss (gain), net of tax <sup>(2)</sup>	2	(3)	12
Unrealized foreign exchange (gain) loss, net of tax <sup>(3)</sup>	(285)	782	269
Realized foreign exchange loss on financing activities, net of tax <sup>(4)</sup>	239	—	—
Gain from investments, net of tax	—	—	(75)
Recoverability charge, net of tax <sup>(5)</sup>	—	21	—
Non-operating items, net of tax	(22)	839	487
<b>Adjusted net earnings from operations</b>	<b>\$ 2,436</b>	<b>\$ 1,977</b>	<b>\$ 1,474</b>

(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, 2025 was an expense of \$26 million (three months ended December 31, 2024 – \$44 million expense, three months ended March 31, 2024 – \$294 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, 2025 was \$3 million (three months ended December 31, 2024 – \$4 million gain, three months ended March 31, 2024 – \$13 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 and are recognized in net earnings. Pre- and after-tax amounts for these unrealized foreign exchange gains and losses are the same.

(4) Realized foreign exchange gains and losses associated with financing activities for the three months ended March 31, 2025 were comprised of a pre- and after-tax foreign exchange loss of \$239 million on the repayment of US dollar denominated debt.

(5) During the fourth quarter of 2024, the Company recognized a pre-tax recoverability charge of \$160 million (\$21 million after-tax) in depletion, depreciation and amortization expense related to refined project scope and cost estimates for planned decommissioning and abandonment activities at the Ninian field in the North Sea in 2024. The costs are considered to be capital in nature, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures.

## 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, 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, repay debt, and provide returns to shareholders through dividends and share buybacks. A reconciliation for adjusted funds flow from cash flows from operating activities is presented below.

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Cash flows from operating activities	\$ 4,284	\$ 3,432	\$ 2,868
Net change in non-cash working capital	(82)	563	15
Abandonment expenditures	188	151	162
Movements in other long-term assets <sup>(1)</sup>	140	40	93
<b>Adjusted funds flow</b>	<b>\$ 4,530</b>	<b>\$ 4,186</b>	<b>\$ 3,138</b>

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, the accrued interest on PRT recoveries, and prepaid cost of service tolls.

## Adjusted Net Earnings from Operations and Adjusted Funds Flow, Per Common 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 12 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.

## 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 and on a total barrels of oil equivalent basis.

The netback calculations include the realized price non-GAAP financial measure which is reconciled below to its respective line item in note 15 to the financial statements.

During the first quarter of 2025, the Company revised its presentation of transportation expense and blending and feedstock costs, showing the expenses on a disaggregated basis in the consolidated statements of earnings. Previously the Company aggregated transportation, blending and feedstock. The revision provides users with more information to evaluate the Company's performance. The financial statements and this MD&A have been updated for all periods presented. As a result, Transportation (\$/BOE, \$/bbl and \$/Mcf) is no longer considered a non-GAAP ratio.

## 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 is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 15 to the financial statements. 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.

(\$ millions, except bbl/d and \$/bbl)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Crude oil and NGLs (bbl/d)</b>			
North America	562,183	533,126	494,621
International			
North Sea	15,665	10,686	13,468
Offshore Africa	11,048	8,423	8,046
Total International	26,713	19,109	21,514
Total sales volumes	588,896	552,235	516,135
Crude oil and NGLs sales <sup>(1)</sup>	\$ 5,624	\$ 4,999	\$ 4,505
Less: Blending and feedstock costs <sup>(2)</sup>	1,391	1,177	1,217
Realized crude oil and NGLs sales	\$ 4,233	\$ 3,822	\$ 3,288
Realized price (\$/bbl)	\$ 79.85	\$ 75.22	\$ 70.01

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

(\$ millions, except BOE/d and \$/BOE)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
<b>Barrels of oil equivalent (BOE/d)</b>			
North America	968,189	911,869	850,336
International			
North Sea	16,399	11,285	13,709
Offshore Africa	12,851	9,507	9,924
Total International	29,250	20,792	23,633
Total sales volumes	997,439	932,661	873,969
Barrels of oil equivalent sales <sup>(1)</sup>	\$ 6,314	\$ 5,424	\$ 5,004
Less: Blending and feedstock costs <sup>(2)</sup>	1,391	1,177	1,217
Less: Sulphur (income) expense	(9)	(3)	1
Realized barrels of oil equivalent sales	\$ 4,932	\$ 4,250	\$ 3,786
Realized price (\$/BOE)	\$ 54.95	\$ 49.54	\$ 47.60

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 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 is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 15 to the financial statements. 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.

(\$ millions, except \$/bbl and royalty rates)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Crude oil and NGLs sales <sup>(1)</sup>	\$ 5,366	\$ 4,830	\$ 4,284
Less: Blending and feedstock costs <sup>(2)</sup>	1,391	1,177	1,217
Realized crude oil and NGLs sales	\$ 3,975	\$ 3,653	\$ 3,067
Realized crude oil and NGLs prices (\$/bbl)	\$ 78.56	\$ 74.46	\$ 68.14
Crude oil and NGLs royalties <sup>(3)</sup>	\$ 756	\$ 747	\$ 563
Crude oil and NGLs royalty rates	19%	20%	18%

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

(3) Item is a component of royalties in note 15 to the financial statements.

## Realized Product Prices – Oil Sands Mining and Upgrading

Realized SCO sales price (\$/bbl) is a non-GAAP ratio calculated as realized SCO sales (a non-GAAP financial measure), divided by SCO sales volumes. Realized SCO sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 15 to the financial statements. 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.

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

(\$ millions, except for bbl/d and \$/bbl)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
SCO sales volumes (bbl/d)	602,048	528,248	453,794
Crude oil and NGLs sales <sup>(1)</sup>	\$ 5,879	\$ 5,362	\$ 4,168
Less: Blending and feedstock costs <sup>(2)</sup>	703	741	499
Realized SCO sales	\$ 5,176	\$ 4,621	\$ 3,669
Realized SCO sales price (\$/bbl)	\$ 95.52	\$ 95.08	\$ 88.84

(1) Crude oil and NGLs sales in note 15 to the financial statements.

(2) Blending and feedstock costs in note 15 to the financial statements.

## Change in Composition of Non-GAAP Financial Measure

During the fourth quarter of 2024, the Company revised the composition of its net capital expenditures non-GAAP financial measure to include acquisition capital related to a number of acquisitions for which agreements between parties have been reached, with closings targeted in 2025. Although subject to regulatory approvals and other customary closing conditions, the inclusion of these acquisitions reflects the Company's estimate of its net capital expenditures at the time the 2025 budget was released. The composition of this measure has been updated to reflect the 2025 capital budget, but did not impact net capital expenditures in 2024.

## 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, net proceeds from investments, and cash flows from investing activities not included in the Company's capital budget. The Company includes acquisition and disposition capital for property, plant and equipment and exploration and evaluation assets in net capital expenditures at close of the transactions. 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.

(\$ millions)	Three Months Ended		
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Cash flows used in investing activities	\$ 1,312	\$ 10,414	\$ 1,392
Working capital acquired	—	(115)	—
Net change in non-cash working capital	(9)	49	(279)
Net capital expenditures	1,303	10,348	1,113
Abandonment expenditures	188	151	162
Capital and abandonment expenditures	\$ 1,491	\$ 10,499	\$ 1,275

## 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 2025	Dec 31 2024	Mar 31 2024
Undrawn bank credit facilities	\$ 4,965	\$ 4,562	\$ 5,450
Cash and cash equivalents	93	131	767
Investments <sup>(1)</sup>	—	—	600
Liquidity	\$ 5,058	\$ 4,693	\$ 6,817

(1) During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for \$25.65 per common share with net proceeds at close, after fees and expenses, of \$575 million.

## Long-term Debt, net

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 11 to the financial statements. A reconciliation of long-term debt, net is presented below.

(\$ millions)			
	Mar 31 2025	Dec 31 2024	Mar 31 2024
Long-term debt	\$ 17,428	\$ 18,819	\$ 11,040
Less: cash and cash equivalents	93	131	767
Long-term debt, net	\$ 17,335	\$ 18,688	\$ 10,273

## 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 11 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)	<b>Mar 31 2025</b>	Dec 31 2024	Mar 31 2024
Interest adjusted after-tax return:			
Net earnings, 12 months trailing	<b>\$ 7,577</b>	\$ 6,106	\$ 7,421
Interest and other financing expense, net of tax, 12 months trailing <sup>(1)</sup>	<b>546</b>	454	477
Interest adjusted after-tax return	<b>\$ 8,123</b>	\$ 6,560	\$ 7,898
12 months average current portion long-term debt <sup>(2)</sup>	<b>\$ 1,615</b>	\$ 1,525	\$ 1,541
12 months average long-term debt <sup>(2)</sup>	<b>11,878</b>	10,642	9,992
12 months average common shareholders' equity <sup>(2)</sup>	<b>39,757</b>	39,635	39,240
12 months average capital employed	<b>\$ 53,250</b>	\$ 51,802	\$ 50,773
After-tax return on average capital employed	<b>15.3%</b>	12.7%	15.6%

(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 2025	Dec 31 2024
<b>ASSETS</b>			
<b>Current assets</b>			
Cash and cash equivalents		\$ 93	\$ 131
Accounts receivable		3,860	4,126
Inventory		2,692	2,793
Prepays and other		493	279
Current portion of other long-term assets	5	96	76
		<b>7,234</b>	7,405
<b>Exploration and evaluation assets</b>	2	<b>2,540</b>	2,526
<b>Property, plant and equipment</b>	3	<b>72,952</b>	73,414
<b>Lease assets</b>	4	<b>1,343</b>	1,394
<b>Other long-term assets</b>	5	<b>745</b>	620
		<b>\$ 84,814</b>	\$ 85,359
<b>LIABILITIES</b>			
<b>Current liabilities</b>			
Accounts payable		\$ 1,187	\$ 1,079
Accrued liabilities		4,386	4,525
Current income taxes payable		127	92
Current portion of long-term debt	6	1,429	2,400
Current portion of other long-term liabilities	7	1,514	1,535
		<b>8,643</b>	9,631
<b>Long-term debt</b>	6	<b>15,999</b>	16,419
<b>Other long-term liabilities</b>	7	<b>9,059</b>	9,302
<b>Deferred income taxes</b>		<b>10,668</b>	10,539
		<b>44,369</b>	45,891
<b>SHAREHOLDERS' EQUITY</b>			
<b>Share capital</b>	9	<b>11,253</b>	11,064
<b>Retained earnings</b>		<b>28,895</b>	28,103
<b>Accumulated other comprehensive income</b>	10	<b>297</b>	301
		<b>40,445</b>	39,468
		<b>\$ 84,814</b>	\$ 85,359

Commitments and contingencies (note 14)

Approved by the Board of Directors on May 7, 2025.

## CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended	
		Mar 31 2025	Mar 31 2024
Product sales	15	\$ 12,712	\$ 9,422
Less: royalties		(1,773)	(1,178)
<b>Revenue</b>		<b>10,939</b>	<b>8,244</b>
<b>Expenses</b>			
Production		2,372	2,157
Blending and feedstock		2,487	1,868
Transportation		653	416
Depletion, depreciation and amortization	3,4	1,870	1,533
Administration		152	126
Share-based compensation	7	26	294
Asset retirement obligation accretion	7	91	97
Interest and other financing expense		258	138
Risk management (gain) loss	13	(24)	38
Foreign exchange (gain) loss		(43)	250
Gain from investments		—	(81)
		<b>7,842</b>	<b>6,836</b>
<b>Earnings before taxes</b>		<b>3,097</b>	<b>1,408</b>
Current income tax expense	8	511	401
Deferred income tax expense	8	128	20
<b>Net earnings</b>		<b>\$ 2,458</b>	<b>\$ 987</b>
<b>Net earnings per common share</b> <sup>(1)</sup>			
Basic	12	\$ 1.17	\$ 0.46
Diluted	12	\$ 1.17	\$ 0.46

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian dollars, unaudited)	Three Months Ended	
	Mar 31 2025	Mar 31 2024
<b>Net earnings</b>	\$ 2,458	\$ 987
<b>Items that may be reclassified subsequently to net earnings</b>		
<b>Net change in derivative financial instruments designated as cash flow hedges</b>		
Unrealized income during the period, net of taxes of \$nil (2024 – \$nil)	4	—
Reclassification to net earnings, net of taxes of \$1 million (2024 – \$nil)	(5)	(1)
	(1)	(1)
<b>Foreign currency translation adjustment</b>		
Translation of net investment	(3)	34
<b>Other comprehensive (loss) income, net of taxes</b>	(4)	33
<b>Comprehensive income</b>	<b>\$ 2,454</b>	<b>\$ 1,020</b>

## CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Three Months Ended	
		Mar 31 2025	Mar 31 2024
<b>Share capital</b>	9		
Balance – beginning of period		\$ 11,064	\$ 10,712
Issued upon exercise of stock options		112	175
Previously recognized liability on stock options exercised for common shares		136	211
Purchase of common shares under Normal Course Issuer Bid		(59)	(68)
Balance – end of period		11,253	11,030
<b>Retained earnings</b>			
Balance – beginning of period		28,103	28,948
Net earnings		2,458	987
Dividends on common shares	9	(1,233)	(1,124)
Purchase of common shares under Normal Course Issuer Bid, including tax	9	(433)	(538)
Balance – end of period		28,895	28,273
<b>Accumulated other comprehensive income</b>	10		
Balance – beginning of period		301	172
Other comprehensive (loss) income, net of taxes		(4)	33
Balance – end of period		297	205
<b>Shareholders' equity</b>		\$ 40,445	\$ 39,508

## CONSOLIDATED STATEMENTS OF CASH FLOWS

(millions of Canadian dollars, unaudited)		Three Months Ended	
		Mar 31 2025	Mar 31 2024
	Note		
<b>Operating activities</b>			
Net earnings		\$ 2,458	\$ 987
Non-cash items			
Depletion, depreciation and amortization	3,4	1,870	1,533
Share-based compensation		26	294
Asset retirement obligation accretion		91	97
Unrealized risk management loss		3	13
Unrealized foreign exchange (gain) loss		(285)	269
Gain from investments		—	(75)
Deferred income tax expense		128	20
Realized foreign exchange on financing activities <sup>(1)</sup>		239	—
Abandonment expenditures	7	(188)	(162)
Other		(140)	(93)
Net change in non-cash working capital		82	(15)
Cash flows from operating activities		4,284	2,868
<b>Financing activities</b>			
Repayment of bank credit facilities and commercial paper, net	6	(491)	—
Repayment of other long-term debt	6	(876)	—
Payment of lease liabilities	4	(84)	(79)
Issue of common shares on exercise of stock options	9	112	175
Dividends on common shares		(1,184)	(1,076)
Purchase of common shares under Normal Course Issuer Bid	9	(487)	(606)
Cash flows used in financing activities		(3,010)	(1,586)
<b>Investing activities</b>			
Net expenditures on exploration and evaluation assets	2,15	(6)	(69)
Net expenditures on property, plant and equipment	3,15	(1,297)	(1,044)
Net change in non-cash working capital		(9)	(279)
Cash flows used in investing activities		(1,312)	(1,392)
<b>Decrease in cash and cash equivalents</b>		<b>(38)</b>	<b>(110)</b>
<b>Cash and cash equivalents – beginning of period</b>		<b>131</b>	<b>877</b>
<b>Cash and cash equivalents – end of period</b>		<b>\$ 93</b>	<b>\$ 767</b>
<b>Interest paid on long-term debt</b>		<b>\$ 257</b>	<b>\$ 181</b>
<b>Income taxes paid, net</b>		<b>\$ 685</b>	<b>\$ 198</b>

(1) Consists of the realized foreign exchange loss on repayment of US dollar denominated debt.

## 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 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, 2024. 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, 2024.

During the first quarter of 2025, the Company revised its presentation of transportation expense and blending and feedstock costs, showing the expenses on a disaggregated basis in the consolidated statements of earnings. Previously the Company aggregated transportation, blending and feedstock costs. The revision provides users with more information to evaluate the Company's performance. The consolidated financial statements and related notes have been updated for all periods presented.

#### **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, including tariffs on certain goods announced by the US government and Canadian countermeasures subsequently announced, both of which are anticipated to evolve. For the three months ended March 31, 2025, these trade actions caused market uncertainty and impacted the global economy, including the oil and gas industry. The Company has taken into account the impacts of the trade actions and the unique circumstances it has created in making estimates, assumptions and judgements in the preparation of the unaudited interim consolidated financial statements, and continues to monitor the developments in the business environment and commodity market. Accordingly, actual results may differ from estimated amounts, and those differences may be material.

#### **Common Share Split and Comparative Figures**

At the Company's Annual and Special Meeting held on May 2, 2024, shareholders passed a Special Resolution approving a two for one common share split effective for shareholders of record as of market close on June 3, 2024. On June 10, 2024, shareholders of record received one additional share for every one common share held, with common shares trading on a split-adjusted basis beginning June 11, 2024. Common share, per common share, dividend, and stock option amounts for periods prior to the two for one common share split have been updated to reflect the common share split.

## 2. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
<b>Cost</b>					
At December 31, 2024	\$ 2,408	\$ —	\$ 48	\$ 70	\$ 2,526
Additions, net	<b>18</b>	—	<b>(1)</b>	—	<b>17</b>
Transfers to property, plant and equipment	<b>(3)</b>	—	—	—	<b>(3)</b>
At March 31, 2025	<b>\$ 2,423</b>	<b>\$ —</b>	<b>\$ 47</b>	<b>\$ 70</b>	<b>\$ 2,540</b>

## 3. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
<b>Cost</b>							
At December 31, 2024	\$ 88,964	\$ 9,731	\$ 5,023	\$ 57,345	\$ 495	\$ 607	\$ 162,165
Additions	<b>840</b>	<b>3</b>	<b>128</b>	<b>319</b>	<b>2</b>	<b>16</b>	<b>1,308</b>
Transfers from exploration and evaluation assets	<b>3</b>	—	—	—	—	—	<b>3</b>
Derecognitions <sup>(1)</sup>	<b>(153)</b>	—	—	<b>(66)</b>	—	—	<b>(219)</b>
Foreign exchange adjustments and other	—	<b>(18)</b>	<b>(9)</b>	—	—	—	<b>(27)</b>
At March 31, 2025	<b>\$ 89,654</b>	<b>\$ 9,716</b>	<b>\$ 5,142</b>	<b>\$ 57,598</b>	<b>\$ 497</b>	<b>\$ 623</b>	<b>\$ 163,230</b>
<b>Accumulated depletion and depreciation</b>							
At December 31, 2024	\$ 62,010	\$ 9,392	\$ 3,885	\$ 12,765	\$ 229	\$ 470	\$ 88,751
Expense	<b>1,068</b>	<b>34</b>	<b>52</b>	<b>638</b>	<b>4</b>	<b>7</b>	<b>1,803</b>
Derecognitions <sup>(1)</sup>	<b>(153)</b>	—	—	<b>(66)</b>	—	—	<b>(219)</b>
Foreign exchange adjustments and other	—	<b>(19)</b>	<b>(25)</b>	<b>(13)</b>	—	—	<b>(57)</b>
At March 31, 2025	<b>\$ 62,925</b>	<b>\$ 9,407</b>	<b>\$ 3,912</b>	<b>\$ 13,324</b>	<b>\$ 233</b>	<b>\$ 477</b>	<b>\$ 90,278</b>
<b>Net book value</b>							
<b>At March 31, 2025</b>	<b>\$ 26,729</b>	<b>\$ 309</b>	<b>\$ 1,230</b>	<b>\$ 44,274</b>	<b>\$ 264</b>	<b>\$ 146</b>	<b>\$ 72,952</b>
At December 31, 2024	\$ 26,954	\$ 339	\$ 1,138	\$ 44,580	\$ 266	\$ 137	\$ 73,414

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

## 4. LEASES

### Lease assets

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2024	\$ 752	\$ 468	\$ 64	\$ 110	\$ 1,394
Additions	2	54	2	26	84
Depreciation	(20)	(31)	(9)	(7)	(67)
Derecognitions	—	(29)	(29)	—	(58)
Foreign exchange adjustments and other	(3)	(5)	(2)	—	(10)
At March 31, 2025	\$ 731	\$ 457	\$ 26	\$ 129	\$ 1,343

### Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at March 31, 2025 were as follows:

	Mar 31 2025	Dec 31 2024
Lease liabilities	\$ 1,406	\$ 1,464
Less: current portion	255	255
	\$ 1,151	\$ 1,209

Total cash outflows for leases for the three months ended March 31, 2025, including payments related to short-term leases not reported as lease assets, were \$354 million (three months ended March 31, 2024 – \$336 million). Interest expense on leases for the three months ended March 31, 2025 was \$16 million (three months ended March 31, 2024 – \$17 million).

## 5. OTHER LONG-TERM ASSETS

	Mar 31 2025	Dec 31 2024
Long-term prepayments, contracts and other <sup>(1)</sup>	\$ 455	\$ 313
Prepaid cost of service tolls	167	166
Long-term inventory	201	204
Risk management (note 13)	18	13
	841	696
Less: current portion	96	76
	\$ 745	\$ 620

(1) Includes physical product sales contracts, accrued interest on PRT recoveries, and the unamortized cost of contributions to the Company's employee bonus program.

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery processes approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), 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 14). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 15).

The carrying value of the Company's interest in NWRP is \$nil, and as at March 31, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$528 million (December 31, 2024 – \$509 million). For the three months ended March 31, 2025, the Company's unrecognized share of the equity loss was \$19 million (three months ended March 31, 2024 – recovery of unrecognized equity losses of \$4 million).

## 6. LONG-TERM DEBT

	<b>Mar 31 2025</b>	Dec 31 2024
<b>Canadian dollar denominated debt, unsecured</b>		
Medium-term notes	<b>\$ 1,466</b>	\$ 1,466
<b>US dollar denominated debt, unsecured</b>		
Bank credit facilities (March 31, 2025 – US\$3,119 million; December 31, 2024 – US\$3,393 million)	<b>4,485</b>	4,888
Commercial paper (March 31, 2025 – US\$394 million; December 31, 2024 – US\$467 million)	<b>566</b>	672
US dollar debt securities (March 31, 2025 – US\$7,650 million; December 31, 2024 – US\$8,250 million)	<b>11,000</b>	11,883
	<b>17,517</b>	18,909
Less: original issue discounts, net <sup>(1)</sup>	<b>12</b>	12
transaction costs <sup>(1) (2)</sup>	<b>77</b>	78
	<b>17,428</b>	18,819
Less: current portion of commercial paper	<b>566</b>	672
current portion of long-term debt <sup>(1) (2)</sup>	<b>863</b>	1,728
	<b>\$ 15,999</b>	\$ 16,419

(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, 2025, the Company had undrawn revolving bank credit facilities of \$4,965 million, and a fully drawn non-revolving term credit facility of \$4,000 million. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit. As at March 31, 2025, the Company had \$566 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 June 2027;
- a \$2,425 million revolving syndicated credit facility, maturing June 2027;
- a \$4,000 million non-revolving term credit facility, maturing December 2027; and
- a \$2,425 million revolving syndicated credit facility, maturing June 2028.

During the first quarter of 2025, the Company extended its \$500 million revolving credit facility originally maturing February 2026 to June 2027.

Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, 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 for the three months ended March 31, 2025 was 5.3% (March 31, 2024 – N/A), and on total long-term debt outstanding for the three months ended March 31, 2025 was 5.0% (March 31, 2024 – 4.8%).

As at March 31, 2025, letters of credit and guarantees aggregating to \$1,505 million were outstanding (December 31, 2024 – \$1,542 million).

## Medium-Term Notes

In July 2023, 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 2025. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.

## US Dollar Debt Securities

During the first quarter of 2025, the Company repaid US\$600 million of 3.90% US dollar debt securities due February 2025.

In July 2023, 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 2025. 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.

## 7. OTHER LONG-TERM LIABILITIES

	<b>Mar 31 2025</b>	Dec 31 2024
Asset retirement obligations	<b>\$ 8,518</b>	\$ 8,607
Lease liabilities (note 4)	<b>1,406</b>	1,464
Share-based compensation	<b>503</b>	620
Transportation and processing contracts	<b>52</b>	58
Risk management (note 13)	<b>19</b>	8
Other	<b>75</b>	80
	<b>10,573</b>	10,837
Less: current portion	<b>1,514</b>	1,535
	<b>\$ 9,059</b>	\$ 9,302

## Asset Retirement Obligations

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.8% (December 31, 2024 – 4.8%) and inflation rates of up to 2% (December 31, 2024 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	<b>Mar 31 2025</b>	Dec 31 2024
Balance – beginning of period	<b>\$ 8,607</b>	\$ 7,690
Liabilities incurred	<b>10</b>	28
Liabilities acquired, net	<b>1</b>	171
Liabilities settled	<b>(188)</b>	(646)
Asset retirement obligation accretion	<b>91</b>	389
Revision of cost, inflation and timing estimates <sup>(1)</sup>	<b>—</b>	417
Change in discount rates	<b>—</b>	419
Foreign exchange adjustments	<b>(3)</b>	139
Balance – end of period	<b>8,518</b>	8,607
Less: current portion	<b>800</b>	787
	<b>\$ 7,718</b>	\$ 7,820

(1) Includes normal course revisions of cost, inflation and timing estimates, as well as revisions related to cost estimate increases on future abandonment of the Ninian field assets in the North Sea.

## Share-Based Compensation

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

	<b>Mar 31 2025</b>	Dec 31 2024
Balance – beginning of period	\$ 620	\$ 780
Share-based compensation expense	26	279
Cash payment for stock options surrendered and PSUs vested	(7)	(84)
Transferred to common shares	(136)	(358)
Other	–	3
Balance – end of period	503	620
Less: current portion	418	463
	<b>\$ 85</b>	<b>\$ 157</b>

## 8. INCOME TAXES

The provision for income tax was as follows:

	Three Months Ended	
<b>Expense (recovery)</b>	<b>Mar 31 2025</b>	Mar 31 2024
Current corporate income tax – North America <sup>(1)</sup>	\$ 569	\$ 412
Current corporate income tax – North Sea	(26)	(5)
Current corporate income tax – Offshore Africa	5	5
Current PRT <sup>(2)</sup> – North Sea	(39)	(14)
Other taxes	2	3
Current income tax	511	401
Deferred corporate income tax	119	14
Deferred PRT <sup>(2)</sup> – North Sea	9	6
Deferred income tax	128	20
Income tax	<b>\$ 639</b>	<b>\$ 421</b>

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

(2) Petroleum Revenue Tax.

## 9. SHARE CAPITAL

### Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	Three Months Ended Mar 31, 2025	
	Number of shares (thousands)	Amount
<b>Issued Common Shares</b>		
Balance – beginning of period	<b>2,102,996</b>	<b>\$ 11,064</b>
Issued upon exercise of stock options	<b>5,658</b>	<b>112</b>
Previously recognized liability on stock options exercised for common shares	–	<b>136</b>
Purchase of common shares under Normal Course Issuer Bid	<b>(11,160)</b>	<b>(59)</b>
Balance – end of period	<b>2,097,494</b>	<b>\$ 11,253</b>

### Dividends

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 5, 2025, the Board of Directors approved a 4% increase in the quarterly dividend to \$0.5875 per common share, beginning with the dividend paid on April 4, 2025.

On October 7, 2024, the Board of Directors approved a 7% increase in the quarterly dividend to \$0.5625 per common share. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to \$0.525 per common share.

### Normal Course Issuer Bid

On March 10, 2025, the Company's application was approved for a Normal Course Issuer Bid to purchase through the facilities of the Toronto Stock Exchange ("TSX"), alternative Canadian trading platforms, and the New York Stock Exchange ("NYSE"), up to 178,738,237 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2025 and ending March 12, 2026.

For the three months ended March 31, 2025, the Company purchased 11,160,000 common shares at a weighted average price of \$43.66 per common share for a total cost, including tax, of \$492 million. Retained earnings were reduced by \$433 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to March 31, 2025, up to and including May 6, 2025, the Company purchased 4,500,000 common shares at a weighted average price of \$39.72 per common share for a total cost, including tax, of \$182 million.

### Share-Based Compensation – Stock Options

The following table summarizes information relating to stock options outstanding as at March 31, 2025:

	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of period	<b>50,806</b>	<b>\$ 33.90</b>
Granted	<b>17,014</b>	<b>\$ 43.57</b>
Exercised for common shares	<b>(5,658)</b>	<b>\$ 19.80</b>
Surrendered for cash settlement	<b>(328)</b>	<b>\$ 19.82</b>
Forfeited	<b>(804)</b>	<b>\$ 35.09</b>
Outstanding – end of period	<b>61,030</b>	<b>\$ 37.96</b>
Exercisable – end of period	<b>12,960</b>	<b>\$ 30.93</b>

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.

## 10. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	<b>Mar 31 2025</b>	Mar 31 2024
Derivative financial instruments designated as cash flow hedges	<b>\$ 69</b>	\$ 71
Foreign currency translation adjustment	<b>228</b>	134
	<b>\$ 297</b>	\$ 205

## 11. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and 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%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at March 31, 2025, the ratio was within the target range at 30.0%.

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.

	<b>Mar 31 2025</b>	Dec 31 2024
Long-term debt	<b>\$ 17,428</b>	\$ 18,819
Less: cash and cash equivalents	<b>93</b>	131
Long-term debt, net	<b>\$ 17,335</b>	\$ 18,688
Total shareholders' equity	<b>\$ 40,445</b>	\$ 39,468
Debt to book capitalization	<b>30.0%</b>	32.1%

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, 2025, the Company was in compliance with this covenant.

## 12. NET EARNINGS PER COMMON SHARE<sup>(1)</sup>

	Three Months Ended	
	<b>Mar 31 2025</b>	Mar 31 2024
Weighted average common shares outstanding		
– basic (thousands of shares)	<b>2,100,540</b>	2,142,086
Effect of dilutive stock options (thousands of shares)	<b>8,537</b>	17,199
Weighted average common shares outstanding		
– diluted (thousands of shares)	<b>2,109,077</b>	2,159,285
Net earnings	<b>\$ 2,458</b>	\$ 987
Net earnings per common share – basic	<b>\$ 1.17</b>	\$ 0.46
– diluted	<b>\$ 1.17</b>	\$ 0.46

(1) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split (note 1).

### 13. FINANCIAL INSTRUMENTS

The Company's financial instruments are comprised of cash and cash equivalents, accounts receivable, risk management assets and liabilities, accounts payable, accrued liabilities, lease liabilities, and long-term debt. These financial instruments, with the exception of risk management assets and liabilities are classified as financial assets and liabilities at amortized cost. 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:

<b>Asset (liability)</b>	<b>Mar 31 2025</b>	Dec 31 2024
Balance – beginning of period	\$ 5	\$ 9
Net liability on outstanding put options <sup>(1)</sup>	(4)	—
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities <sup>(2) (3) (4)</sup>	(2)	(6)
Foreign exchange	1	1
Other comprehensive income	(1)	1
Balance – end of period	(1)	5
Less: current portion	(1)	5
	\$ —	\$ —

(1) Represents net premiums received on outstanding foreign currency put option contracts entered into during the first quarter of 2025.

(2) Risk management assets and liabilities are disclosed in note 5 and note 7, respectively.

(3) In the fourth quarter of 2024, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US\$1.47 AECO, and 25,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2025.

(4) In the fourth quarter of 2023, the Company entered into fixed price financial contracts to buy 50,000 MMBtu/d of natural gas at US\$1.82 AECO for the period of January to December 2024.

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

	Three Months Ended	
	<b>Mar 31 2025</b>	Mar 31 2024
Net realized risk management (gain) loss	\$ (27)	\$ 25
Net unrealized risk management loss	3	13
	\$ (24)	\$ 38

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 values of the Company's fixed rate long-term debt is outlined below:

	<b>Mar 31, 2025</b>	
	<b>Carrying amount</b>	<b>Level 1 Fair Value</b>
Fixed rate long-term debt <sup>(1) (2)</sup>	\$ 12,377	\$ 12,423

(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 consolidated financial statements for the year ended December 31, 2024.

### **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. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

#### **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. As at March 31, 2025, the Company had no interest rate swap contracts outstanding.

#### **Foreign currency exchange rate risk management**

The Company is exposed to foreign currency exchange rate risk in Canada primarily related to its US dollar denominated long-term debt, commercial paper and working capital. The Company is also exposed to foreign currency exchange rate risk on transactions conducted in other currencies and in the carrying value of its foreign subsidiaries. The Company periodically enters into foreign currency forward contracts, foreign exchange options contracts, banker's acceptances, and commercial paper to mitigate its foreign currency exchange rate risk.

As at March 31, 2025, the Company had US\$2,504 million of foreign currency forward contracts outstanding (December 31, 2024 – US\$2,187 million), with original terms of up to 90 days, of which US\$2,109 million were designated as derivatives held for trading (December 31, 2024 – US\$1,521 million) and US\$395 million were designated as cash flow hedges (December 31, 2024 – US\$666 million).

As at March 31, 2025, the Company had US\$2,100 million of outstanding foreign currency put option contracts sold to various counterparties at a weighted average strike price of US\$0.7104 and expirations of up to 31 days. These put option contracts grant the purchaser the right, but not the obligation to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

### **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, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at March 31, 2025, 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. 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, 2025, 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	\$	1,187	\$ —	\$ —	\$ —
Accrued liabilities	\$	4,386	\$ —	\$ —	\$ —
Long-term debt <sup>(1)</sup>	\$	1,429	\$ 441	\$ 7,586	\$ 8,061
Other long-term liabilities <sup>(2)</sup>	\$	274	\$ 153	\$ 378	\$ 620
Interest and other financing expense <sup>(3)</sup>	\$	946	\$ 926	\$ 1,859	\$ 3,433

(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, \$255 million; one to less than two years, \$153 million; two to less than five years, \$378 million; and thereafter, \$620 million.

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at March 31, 2025.

### 14. 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, 2025:

	Remaining 2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases and processing <sup>(1)</sup>	\$ 1,701	\$ 2,272	\$ 2,126	\$ 1,993	\$ 1,891	\$ 19,219
North West Redwater Partnership service toll <sup>(2)</sup>	\$ 104	\$ 118	\$ 98	\$ 100	\$ 98	\$ 4,054
Offshore vessels and equipment	\$ 28	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and power	\$ 35	\$ 29	\$ 29	\$ 28	\$ 27	\$ 216
Other	\$ 112	\$ 110	\$ 19	\$ 20	\$ 19	\$ 208

(1) The Company's commitment for its 20-year product transportation agreement ending in 2044 on the Trans Mountain Expansion ("TMX") pipeline reflects interim tolls approved by the Canada Energy Regulator in the fourth quarter of 2023, and is subject to change pending the approval of final tolls.

(2) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is \$1,977 million of interest payable over the 40-year tolling period, ending in 2058 (note 5).

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.

## 15. SEGMENTED INFORMATION

(millions of Canadian dollars, unaudited)	North America		North Sea		Offshore Africa		Total Exploration and Production	
	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Mar 31		Mar 31		Mar 31		Mar 31	
	2025	2024	2025	2024	2025	2024	2025	2024
<b>Segmented product sales</b>								
Crude oil and NGLs	\$ 5,366	\$ 4,284	\$ 152	\$ 139	\$ 106	\$ 82	\$ 5,624	\$ 4,505
Natural gas	671	485	6	1	13	13	690	499
Other income and revenue <sup>(1)</sup>	17	(2)	—	4	1	—	18	2
<b>Total segmented product sales</b>	<b>6,054</b>	<b>4,767</b>	<b>158</b>	<b>144</b>	<b>120</b>	<b>95</b>	<b>6,332</b>	<b>5,006</b>
Less: royalties	(781)	(583)	—	—	(5)	(5)	(786)	(588)
<b>Segmented revenue</b>	<b>5,273</b>	<b>4,184</b>	<b>158</b>	<b>144</b>	<b>115</b>	<b>90</b>	<b>5,546</b>	<b>4,418</b>
<b>Segmented expenses</b>								
Production	894	909	170	106	35	21	1,099	1,036
Blending and feedstock	1,391	1,217	—	—	—	—	1,391	1,217
Transportation	476	342	3	1	—	—	479	343
Depletion, depreciation and amortization	1,092	941	40	17	59	47	1,191	1,005
Asset retirement obligation accretion	53	58	14	16	2	2	69	76
Risk management (gain) loss (commodity derivatives)	(12)	3	—	—	—	—	(12)	3
<b>Total segmented expenses</b>	<b>3,894</b>	<b>3,470</b>	<b>227</b>	<b>140</b>	<b>96</b>	<b>70</b>	<b>4,217</b>	<b>3,680</b>
<b>Segmented earnings (loss)</b>	<b>\$ 1,379</b>	<b>\$ 714</b>	<b>\$ (69)</b>	<b>\$ 4</b>	<b>\$ 19</b>	<b>\$ 20</b>	<b>\$ 1,329</b>	<b>\$ 738</b>
<b>Non-segmented expenses</b>								
Administration								
Share-based compensation								
Interest and other financing expense								
Risk management (gain) loss (other)								
Foreign exchange (gain) loss								
Gain from investments								
<b>Total non-segmented expenses</b>								
<b>Earnings before taxes</b>								
Current income tax								
Deferred income tax								
<b>Net earnings</b>								

(millions of Canadian dollars, unaudited)	<b>Oil Sands Mining and Upgrading</b>		<b>Midstream and Refining</b>		<b>Inter-segment Elimination and Other</b>		<b>Total</b>	
	Three Months Ended		Three Months Ended		Three Months Ended		Three Months Ended	
	Mar 31		Mar 31		Mar 31		Mar 31	
	<b>2025</b>	2024	<b>2025</b>	2024	<b>2025</b>	2024	<b>2025</b>	2024
<b>Segmented product sales</b>								
Crude oil and NGLs <sup>(2)</sup>	\$ 5,879	\$ 4,168	\$ 22	\$ 20	\$ 207	\$ (17)	\$ 11,732	\$ 8,676
Natural gas	—	—	—	—	26	30	716	529
Other income and revenue <sup>(1)</sup>	25	1	221	214	—	—	264	217
<b>Total segmented product sales</b>	<b>5,904</b>	4,169	<b>243</b>	234	<b>233</b>	13	<b>12,712</b>	9,422
Less: royalties	(987)	(590)	—	—	—	—	(1,773)	(1,178)
<b>Segmented revenue</b>	<b>4,917</b>	3,579	<b>243</b>	234	<b>233</b>	13	<b>10,939</b>	8,244
<b>Segmented expenses</b>								
Production	1,185	1,026	73	79	15	16	2,372	2,157
Blending and feedstock <sup>(2)</sup>	703	499	172	153	221	(1)	2,487	1,868
Transportation	174	69	4	5	(4)	(1)	653	416
Depletion, depreciation and amortization	675	524	4	4	—	—	1,870	1,533
Asset retirement obligation accretion	22	21	—	—	—	—	91	97
Risk management (gain) loss (commodity derivatives)	—	—	—	—	—	—	(12)	3
<b>Total segmented expenses</b>	<b>2,759</b>	2,139	<b>253</b>	241	<b>232</b>	14	<b>7,461</b>	6,074
<b>Segmented earnings (loss)</b>	<b>\$ 2,158</b>	\$ 1,440	<b>\$ (10)</b>	\$ (7)	<b>\$ 1</b>	\$ (1)	<b>\$ 3,478</b>	\$ 2,170
<b>Non-segmented expenses</b>								
Administration							152	126
Share-based compensation							26	294
Interest and other financing expense							258	138
Risk management (gain) loss (other)							(12)	35
Foreign exchange (gain) loss							(43)	250
Gain from investments							—	(81)
<b>Total non-segmented expenses</b>							<b>381</b>	762
<b>Earnings before taxes</b>							<b>3,097</b>	1,408
Current income tax							511	401
Deferred income tax							128	20
<b>Net earnings</b>							<b>\$ 2,458</b>	\$ 987

(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 <sup>(1)</sup>

Three Months Ended

	Mar 31, 2025			Mar 31, 2024		
	Net expenditures	Non-cash and fair value changes <sup>(2)</sup>	Capitalized costs	Net expenditures	Non-cash and fair value changes <sup>(2)</sup>	Capitalized costs
<b>Exploration and evaluation assets</b>						
Exploration and Production						
North America	\$ 7	\$ 8	\$ 15	\$ 69	\$ (23)	\$ 46
Offshore Africa	(1)	—	(1)	—	—	—
	6	8	14	69	(23)	46
<b>Property, plant and equipment</b>						
Exploration and Production						
North America	829	(139)	690	632	(146)	486
North Sea	3	—	3	4	—	4
Offshore Africa	128	—	128	41	—	41
	960	(139)	821	677	(146)	531
Oil Sands Mining and Upgrading	319	(66)	253	353	(68)	285
Midstream and Refining	2	—	2	4	—	4
Head Office	16	—	16	10	—	10
	1,297	(205)	1,092	1,044	(214)	830
	\$ 1,303	\$ (197)	\$ 1,106	\$ 1,113	\$ (237)	\$ 876

(1) This table provides a reconciliation of capitalized costs, reported in note 2 and note 3, 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 2025	Dec 31 2024
Exploration and Production		
North America	\$ 32,287	\$ 32,670
North Sea	842	702
Offshore Africa	1,355	1,412
Other	26	31
Oil Sands Mining and Upgrading	48,927	49,221
Midstream and Refining	1,123	1,099
Head Office	254	224
	\$ 84,814	\$ 85,359

## 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 2023. 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, 2025:

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Interest coverage (times)	
Net earnings <sup>(1)</sup>	14.7x
Adjusted funds flow <sup>(2)</sup>	26.1x

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

(2) Adjusted funds flow (as defined in the Company's Management's Discussion and Analysis), plus current income taxes and interest expense; divided by interest expense.

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## CORPORATE INFORMATION

### Board of Directors

Catherine M. Best, FCA, ICD.D  
M. Elizabeth Cannon, Ph.D, O.C.  
N. Murray Edwards, O.C.  
Christopher L. Fong  
Ambassador Gordon D. Giffin  
Wilfred A. Gobert  
Christine M. Healy  
Steve W. Laut  
Honourable Frank J. McKenna, P.C., O.C., O.N.B., K.C.  
Scott G. Stauth  
David A. Tuer  
Annette M. Verschuren, O.C.

### Officers

N. Murray Edwards  
*Executive Chairman*

Scott G. Stauth  
*President*

Jay E. Froc  
*Chief Operating Officer, Oil Sands*

Robin S. Zabek  
*Chief Operating Officer, Exploration and Production*

Ron K. Laing  
*Chief Commercial and Corporate Development Officer*

Victor C. Darel  
*Chief Financial Officer*

Troy J.P. Andersen  
*Senior Vice-President, Canadian Conventional Field Operations*

Calvin J. Bast  
*Senior Vice-President, Production*

Dwayne F. Giggs  
*Senior Vice-President, Exploration*

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*Senior Vice-President, Finance*

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*Senior Vice-President, Exploitation*

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*Senior Vice-President, Oil Sands Mining and Upgrading*

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*Vice-President, Land*

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*Vice-President, Marketing*

Kyle G. Pisio  
*Vice-President, Drilling, Completions and Asset Retirement*

Stephanie A. Graham  
*Corporate Secretary and Associate General Counsel, Canada*

### 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

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Computershare Investor Services LLC  
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