FOURTH QUARTER REPORT

THREE MONTHS AND YEAR ENDED DECEMBER 31, 2024 TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED
2024 FOURTH QUARTER AND YEAR END RESULTS

Canadian Natural's President, Scott Stauth, commented on the Company's 2024 fourth quarter and year end results, "2024 was an excellent year for us, as we achieved strong growth and set several new production records from our base operations, before including acquisitions that closed in 2024. Additionally, including acquisitions, we achieved record annual average production of over 1,363,000 BOE/d in 2024, which includes record annual liquids production of over one million barrels per day. At our world class Oil Sands Mining and Upgrading assets, we achieved record quarterly and annual Synthetic Crude Oil ("SCO") production of approximately 535,000 bbl/d and 472,000 bbl/d respectively. This strong operational performance resulted in a high annual utilization rate of 99%, anchored by industry leading SCO operating costs of $20.97/bbl (US$15.00/bbl) for Q4/24 and $22.88/bbl (US$16.70/bbl) for full year 2024, which drove significant free cash flow in the year. Thermal in situ production also reached record annual production levels of approximately 271,000 bbl/d combined with strong operating costs of $11.04/bbl (US$8.06/bbl). Our conventional crude oil and liquids-rich natural gas operations continue to provide significant free cash flow with further potential for flexible organic growth. When combined with our entire portfolio, we have significant organic growth opportunities.

Following the previously announced acquisition at the Athabasca Oil Sands Project ("AOSP") that closed in December 2024, and the AOSP swap transaction targeted to close in the first half of 2025, Canadian Natural's working interest will be 100% in the Albian mines and 80% in the non-operated Scotford Upgrader. Further, when combined with Horizon, our total oil sands mining production capacity is currently targeted at approximately 592,000 bbl/d, up from 570,000 bbl/d, following completion of the Horizon Reliability Enhancement Project and the Debottleneck Project at the Scotford Upgrader in 2024. These acquisitions are immediately cash flow accretive and when combined with the production capacity increases, drive significant value to shareholders for decades with no production decline. With our long history of driving value through continuous improvement that is engrained in our culture, we remain focused on delivering additional value from these world class assets, providing incremental and sustainable free cash flow.

Canadian Natural's reserves compete on a global scale supporting long-term organic growth opportunities, with total proved reserves of 15.2 billion BOE and total proved plus probable reserves of 20.1 billion BOE as of year end 2024, both of which increased 9% from year end 2023 levels. With approximately 74% of the Company's total proved reserves being long life low decline, the strength and depth of our assets is evident and provides us with a total proved reserves life index ("RLI") of 33 years and a total proved plus probable RLI of 44 years. This includes Oil Sands Mining and Upgrading reserves that have a total proved RLI of 43 years, providing significant production for decades.

We have a long track record of consistently delivering strong, industry leading results driven by our safe, reliable operations and relentless focus on continuous improvement, which maximizes long-term shareholder value."

Canadian Natural's Chief Financial Officer, Mark Stainthorpe, added "In 2024, we delivered strong financial results, with annual adjusted net earnings of approximately $7.4 billion and adjusted funds flow of $14.9 billion, including Q4/24 adjusted net earnings of approximately $2.0 billion and adjusted funds flow of $4.2 billion. We returned approximately $7.1 billion to shareholders in 2024, inclusive of our sustainable and growing dividend and share repurchases. We increased our quarterly dividend twice in 2024 and subsequent to year end, the Board approved a 4% increase to $2.35 per common share annualized, with 2025 being the 25th consecutive year of dividend increases by Canadian Natural, with a compound annual growth rate ("CAGR") of 21% over that time.

After the recent acquisitions, our US$ WTI breakeven remains top tier in the low to mid-$40 per barrel range and our balance sheet remains strong with year end metrics including Debt to Book Capitalization at 32% and Debt to Adjusted EBITDA at 1.1x. Our large, diverse portfolio is supported by long life low decline assets, which drive top tier operating costs and low maintenance capital. When combined, it results in significant and sustainable free cash flow that we can repeat for decades."

KEY 2024 ANNUAL OPERATIONAL HIGHLIGHTS

- Record total production of approximately 1,363,000 BOE/d.
- Record total corporate liquids production of approximately 1,006,000 bbl/d.
  - Strong total corporate liquids operating costs(1) of $18.56/bbl (US$13.55/bbl).
- Record Oil Sands Mining and Upgrading production of approximately 472,000 bbl/d of zero decline SCO, with upgrader utilization of 99%, including planned turnarounds.
  - Industry leading Oil Sands Mining and Upgrading operating costs of $22.88/bbl (US$16.70/bbl) of SCO.
- Record thermal in situ production of approximately 271,000 bbl/d of long life low decline production.
  - Strong thermal in situ operating costs of $11.04/bbl (US$8.06/bbl).

KEY 2024 FOURTH QUARTER OPERATIONAL HIGHLIGHTS

- Record total production of approximately 1,470,000 BOE/d.
- Record total corporate liquids production of approximately 1,090,000 bbl/d.
  - Strong total corporate liquids operating costs of $16.98/bbl (US$12.14/bbl).
- Record Oil Sands Mining and Upgrading production of approximately 535,000 bbl/d of zero decline SCO, with upgrader utilization of 105%, including planned turnarounds.
  - Industry leading Oil Sands Mining and Upgrading operating costs of $20.97/bbl (US$15.00/bbl) of SCO.
- Record natural gas production of 2,283 MMcf/d.

CREATING LONG-TERM SHAREHOLDER VALUE

- Canadian Natural has unlocked significant long-term shareholder value at the Albian mines and Scotford Upgrader ("AOSP") since its initial acquisition of a 70% working interest in 2017, followed by 20% in December 2024 and the final 10% in the Muskeg River and Jackpine mines ("Albian mines"), which is targeted to close in the first half of 2025. The Company has strategically acquired this world class asset and added significant value by increasing production and reducing operating costs through implementing process improvements and optimization projects to improve reliability and increase utilization. Since 2017, Canadian Natural has:
  - Increased gross production at the Albian mines by 30% or over 70,000 bbl/d. Upgrader capacity was also increased to match the increased production from the mines.
  - Decreased AOSP per unit operating costs by over 30% or approximately $10/bbl. This equates to incremental margin of approximately $0.8 billion based on 2024 production.
  - With 100% working interest in the Albian mines, once the swap transaction closes, Canadian Natural is targeting to unlock further value through its effective and efficient operations and relentless continuous improvement culture.
- Subsequent to year end, Oil Sands Mining and Upgrading continued to achieve strong production and high utilization. In January 2025 and February 2025, production averaged on a gross basis approximately **634,000 bbl/d** over the two months. February 2025 was the highest monthly gross production in our history at approximately **640,000 bbl/d** as we focus on continuous improvement initiatives combined with strong performance from the Reliability Enhancement Project at Horizon and Debottleneck Project at the Scotford Upgrader.
  - Additionally, further value has been unlocked from piping modifications completed during the recent Debottleneck Project at the Scotford Upgrader. These modifications unlock approximately 5,000 bbl/d of annual gross production from the Albian mines, resulting in higher utilization during planned upgrader turnarounds. This increased zero decline production will continue to benefit Canadian Natural for decades, including our increased ownership in the Albian mines.
  - The Company's 2025 corporate production guidance will be increased following the closing of the previously announced swap transaction where Canadian Natural will add approximately 31,000 bbl/d of bitumen.

(1) Operating costs are calculated as production expense divided by respective sales volumes. Natural gas and NGLs production volumes approximate sales volumes.

HIGHLIGHTS

($ millions, except per common share amounts)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Net earnings	**$ 1,138**	$ 2,266	$ 2,627	**$ 6,106**	$ 8,233
Per common share (1) – basic	**$ 0.54**	$ 1.07	$ 1.22	**$ 2.87**	$ 3.77
– diluted	**$ 0.54**	$ 1.06	$ 1.21	**$ 2.85**	$ 3.74
Adjusted net earnings from operations (2)	**$ 1,977**	$ 2,071	$ 2,546	**$ 7,414**	$ 8,533
Per common share (1) – basic (3)	**$ 0.94**	$ 0.98	$ 1.18	**$ 3.49**	$ 3.91
– diluted (3)	**$ 0.93**	$ 0.97	$ 1.17	**$ 3.46**	$ 3.87
Cash flows from operating activities	**$ 3,432**	$ 3,002	$ 4,815	**$ 13,386**	$ 12,353
Adjusted funds flow (2)	**$ 4,186**	$ 3,921	$ 4,419	**$ 14,859**	$ 15,274
Per common share (1) – basic (3)	**$ 1.99**	$ 1.85	$ 2.05	**$ 6.99**	$ 7.00
– diluted (3)	**$ 1.97**	$ 1.84	$ 2.03	**$ 6.94**	$ 6.93
Cash flows used in investing activities	**$ 10,414**	$ 1,274	$ 946	**$ 14,095**	$ 4,858
Net capital expenditures (4)	**$ 10,348**	$ 1,349	$ 975	**$ 14,431**	$ 4,909
Net capital expenditures, excluding net acquisition costs (5)	**$ 1,290**	$ 1,349	$ 1,019	**$ 5,286**	$ 4,883
Abandonment expenditures	**$ 151**	$ 204	$ 149	**$ 646**	$ 509
Daily production, before royalties					
Natural gas (MMcf/d)	**2,283**	2,049	2,231	**2,147**	2,151
Crude oil and NGLs (bbl/d)	**1,090,002**	1,021,572	1,047,541	**1,005,603**	973,530
Equivalent production (BOE/d) (6)	**1,470,428**	1,363,086	1,419,313	**1,363,496**	1,332,105

(1) Per common share and dividend amounts have been updated to reflect the two for one common share split. Further details are disclosed in the Advisory section of the Company's MD&A and in the financial statements for the three months and year ended December 31, 2024 dated March 5, 2025.

(2) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2024 dated March 5, 2025.

(3) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2024 dated March 5, 2025.

(4) Non-GAAP Financial Measure. The composition of this measure was updated in the fourth quarter of 2024 and 2023 and has been updated for all periods presented. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2024 dated March 5, 2025.

(5) Calculated as net capital expenditures, less net property acquisitions (dispositions) for exploration and evaluation assets and property, plant and equipment for Exploration and Production and Oil Sands Mining and Upgrading, as reported in the Company's MD&A.

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

ANNUAL HIGHLIGHTS

- The strength of Canadian Natural's long life low decline asset base, supported by safe, effective and efficient operations, makes our business unique, robust and sustainable. In 2024, the Company generated strong financial results, including:
  - Net earnings of approximately $6.1 billion and adjusted net earnings from operations of approximately $7.4 billion.
  - Cash flows from operating activities of approximately $13.4 billion.
  - Adjusted funds flow of approximately $14.9 billion.
- The Company's disciplined 2024 operating capital program, excluding net acquisition costs, was approximately $100 million under budget at $5.3 billion. Abandonment expenditures were essentially on budget.
  - Our 2025 disciplined operating capital budget of approximately $6.0 billion, along with $787 million of abandonment expenditures before recoveries, $90 million on carbon capture and $45 million on a one-time office move, all remain on track.

- In 2024, Canadian Natural delivered record annual average production of 1,363,496 BOE/d, an increase of 2% or approximately 31,400 BOE/d from 2023 levels, or 5% on a production per share basis.
  - The Company achieved record annual total liquids production of 1,005,603 bbl/d in 2024, an increase of 3% or approximately 32,000 bbl/d from 2023 levels. Strong annual liquids production in 2024 was driven by:
    - Record annual Oil Sands Mining and Upgrading production of 472,245 bbl/d of SCO in 2024, an increase of 5% or approximately 21,000 bbl/d from 2023 levels.
      - Industry leading annual Oil Sands Mining and Upgrading operating costs of $22.88/bbl (US$16.70/bbl) of SCO were achieved in 2024, a decrease of 6% from 2023 levels.
    - Record annual thermal in situ production of 271,011 bbl/d, an increase of 3% or approximately 9,000 bbl/d from 2023 levels.
      - Annual thermal in situ operating costs were strong, averaging $11.04/bbl (US$8.06/bbl) in 2024, a decrease of 16% from 2023 levels.
- During 2024, the Company increased its contracted crude oil transportation capacity to 256,500 bbl/d, expanding its committed volumes to Canada's west coast and to the United States Gulf Coast ("USGC") to approximately 23% of 2025 targeted liquids production based on the mid-point of 2025 corporate annual guidance. The additional egress supports Canadian Natural's long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.
  - In December 2024, the Company increased its total committed capacity on the Trans Mountain Expansion ("TMX") pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d, further expanding access to Canada's west coast.
  - In Q1/24, the Company increased its total committed capacity on the Flanagan South pipeline to 77,500 bbl/d, an incremental 55,000 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC.
  - The Company also has committed capacity of 10,000 bbl/d on the Keystone Base pipeline, with direct access to the USGC.
- In December 2024, Canadian Natural closed the acquisition of Chevron's Alberta assets, including a 20% interest in AOSP and a 70% operated working interest in light crude oil and liquids-rich natural gas assets in the Duvernay play. Both of these acquisitions are targeted to contribute significant additional free cash flow to the Company.
  - This acquisition brought Canadian Natural's total working interest in AOSP to 90%, adding approximately 62,500 bbl/d of long life no decline SCO production.
  - The Duvernay assets add approximately 60,000 BOE/d in 2025, consisting of 30,000 bbl/d of liquids and 179 MMcf/d of natural gas, providing meaningful near term, drill to fill, liquids-rich natural gas growth.
- Subsequent to year end, Canadian Natural announced an agreement to swap Shell's remaining 10% working interest in the Albian mines for 10% working interest in the Scotford Upgrader and Quest Carbon Capture and Storage facilities. After closing, this swap brings Canadian Natural's total working interest in the Albian mines to 100% and adds approximately 31,000 bbl/d of incremental bitumen production.
  - Following closing of the swap transaction, total Oil Sands Mining and Upgrading production capacity increases to approximately 592,000 bbl/d, 90% of which is SCO.
- Canadian Natural maintains a strong balance sheet and financial flexibility, with approximately $4.7 billion in liquidity(1) as at December 31, 2024. Debt ratios remain strong with a Debt to Book Capitalization of 32% and a Debt to Adjusted EBITDA of 1.1x. The Company executed on a number of initiatives in 2024 to strengthen its financial flexibility, including:
  - Repaid $320 million of medium-term notes and US$500 million of US debt securities.
  - Issued $500 million of medium-term notes and US$1,500 million of US debt securities.
  - In connection with the acquisition of assets from Chevron, the Company entered into a $4,000 million non-revolving term credit facility maturing December 2027.
  - Extended the Company's $2,425 million revolving syndicated credit facility from June 2025 to June 2028, and its $500 million revolving credit facility from February 2025 to February 2026.
  - Subsequent to year end, the Company repaid US$600 million due February 2025.

(1) Non-GAAP Financial Measure. Refer to the "Non-GAAP and Other Financial Measures" section of this press release and the Company's MD&A for the three months and year ended December 31, 2024 dated March 5, 2025.

QUARTERLY HIGHLIGHTS

- In Q4/24, the Company generated strong financial results, including:
  - Net earnings of approximately $1.1 billion and adjusted net earnings from operations of approximately $2.0 billion.
  - Cash flows from operating activities of approximately $3.4 billion.
  - Adjusted funds flow of approximately $4.2 billion.
- Canadian Natural achieved record quarterly average production of 1,470,428 BOE/d in Q4/24, consisting of record liquids production of 1,090,002 bbl/d and record natural gas production of 2,283 MMcf/d. The total BOE/d production represents a 4% increase from Q4/23 levels and an 8% increase from Q3/24 levels.
  - Oil Sands Mining and Upgrading achieved record quarterly production of 534,631 bbl/d of SCO in Q4/24, including planned turnaround activities. Quarterly production volumes increased 7% or approximately 34,500 bbl/d from Q4/23 levels.
    - Industry leading annual Oil Sands Mining and Upgrading operating costs of $20.97/bbl (US$15.00/bbl) were achieved in Q4/24.
    - At AOSP, the planned turnaround was successfully completed on October 18, 2024. Due to strong execution, the annual net production impact to AOSP from the planned turnaround was reduced to approximately 5,400 bbl/d, a significant improvement compared to the budgeted annual net production impact of 11,000 bbl/d.
    - Additionally, a Debottleneck Project was completed at the Scotford Upgrader which increased gross capacity at AOSP by approximately 8,000 bbl/d in October 2024.

RETURNS TO SHAREHOLDERS

- Returns to shareholders in 2024 were significant, totaling approximately $7.1 billion, comprised of $4.4 billion of dividends and $2.7 billion through the repurchase and cancellation of approximately 55.4 million common shares at a weighted average price of $48.07 per share.
  - In Q4/24, the Company returned a total of approximately $1.7 billion directly to shareholders through $1.1 billion in dividends and $0.6 billion through the repurchase and cancellation of approximately 11.7 million common shares at a weighted average price of $47.08 per share.
- Free cash flow is defined as adjusted funds flow, less capital and dividends. The Company will manage the allocation of free cash flow on a forward-looking annual basis, while managing working capital and cash management as required. As previously disclosed on October 7, 2024, the Board of Directors has adjusted the free cash flow allocation policy 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.
- Subsequent to year end, the Board of Directors approved a 4% increase to the quarterly cash dividend to $0.5875 per common share, from $0.5625 per common share, payable on April 4, 2025 to shareholders of record at the close of business on March 21, 2025. This represents an annualized dividend of $2.35 per common share.
  - The Company has a leading track record of dividend increases, with 2025 being the 25th consecutive year of dividend increases, with a CAGR of 21% over that time. This demonstrates the confidence that the Board 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.
- Subsequent to year end, on March 5, 2025, the Board of Directors approved the renewal of the Company's Normal Course Issuer Bid ("NCIB"), which states that during the 12 month period commencing on March 13, 2025 and ending on March 12, 2026, the Company can repurchase for cancellation up to 10% of the public float (as determined in accordance with the rules of the TSX), subject to TSX approval.

RESERVES HIGHLIGHTS

A key differentiator for Canadian Natural is the strength, diversity and balance of its world class, top tier assets. The Company's total proved reserve life index ("RLI")(1) of 33 years is supported by long life low decline assets that have been strategically assembled and developed over several decades. The low maintenance capital requirements relative to the size and quality of the reserves affords the Company significant flexibility when balancing its four pillars of capital allocation to maximize shareholder value.

The Company's reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators ("IQREs"). The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2024 (all reserves values are Company Gross unless stated otherwise).

- Total proved reserves increased 9% to 15.231 billion BOE, with reserves additions and revisions of 1.820 billion BOE. Total proved plus probable reserves increased 9% to 20.110 billion BOE, with reserves additions and revisions of 2.105 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 74% of total proved reserves are long life low decline reserves. This results in a total proved BOE RLI of 33 years and a total proved plus probable BOE RLI of 44 years.
    - Additionally, high value, zero decline SCO represents approximately 50% of total proved reserves with a RLI of 43 years.
- Proved developed producing reserves additions and revisions are 1.322 million BOE, replacing 2024 production by 265%. The proved developed producing BOE RLI is 21 years.
- Total proved reserves additions and revisions replaced 2024 production by 365%. Total proved plus probable reserves additions and revisions replaced 2024 production by 422%.
- In 2024, Canadian Natural continued to achieve strong finding and development costs:
  - Finding, development and acquisition ("FD&A")(1) costs, excluding changes in Future Development Cost ("FDC"), are $7.82/BOE for total proved reserves and $6.76/BOE for total proved plus probable reserves.
  - FD&A costs, including changes in FDC, are $13.56/BOE for total proved reserves and $12.60/BOE for total proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, is $118.3 billion for proved developed producing reserves, $170.2 billion for total proved reserves, and $205.7 billion for total proved plus probable reserves.
  - The Company's total proved net asset value ("NAV") per share increased to $74.83 per share in 2024 from $69.53 per share in 2023 after adjusting for asset retirement obligations, net debt and the share split that occurred in June 2024. Total proved plus probable NAV per share increased to $91.72 per share in 2024 from $84.83 per share in 2023.

(1) Supplementary financial measure. Refer to the "2024 Year End Reserves" section of this document.

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

	Year Ended			
	December 31, 2024		December 31, 2023	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [1]	**313**	**307**	228	221
Natural gas	**94**	**78**	78	61
Dry	**2**	**2**	2	2
Subtotal	**409**	**387**	308	284
Stratigraphic test / service wells	**474**	**407**	481	419
Total	**883**	**794**	789	703
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 387 net crude oil and natural gas producer wells in 2024, 103 more than in 2023.
- In 2024, the Company reallocated capital from certain dry natural gas development activity to multilateral primary heavy crude oil wells, given the success of our multilateral programs and low natural gas prices in 2024.

North America Exploration and Production

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs production (bbl/d)	**255,729**	228,221	243,157	**238,277**	234,100
Net wells targeting crude oil	**84**	59	42	**214**	173
Net successful wells drilled	**84**	58	42	**213**	171
Success rate	**100%**	98%	100%	**99%**	99%

- North America E&P liquids annual production, excluding thermal in situ, averaged 238,277 bbl/d in 2024, a 2% increase from 2023 levels, reflecting strong results from our liquids-rich natural gas and primary heavy crude oil drilling activity as well as the recently acquired Duvernay assets.
  - Primary heavy crude oil production averaged 79,128 bbl/d in 2024, a 2% increase from 2023 levels, reflecting strong drilling results from the Company's multilateral wells, partially offset by natural field declines.
    - Canadian Natural drilled 121 net horizontal multilateral primary heavy crude oil wells in 2024, compared to 104 in 2023. Multilateral wells combine increased reservoir capture and higher production with reduced servicing requirements which lowers operating costs. The Company continues to optimize well design and lengths in our highly successful multilateral program, achieving top tier average initial peak rates of approximately 250 bbl/d per well, which is 43% higher than budget average initial peak rates of 175 bbl/d per well, and a further 9% higher than the previously disclosed rate of 230 bbl/d.
    - Operating costs in the Company's primary heavy crude oil operations averaged $18.11/bbl (US$13.22/bbl) in 2024, a decrease of 9% from 2023 levels, primarily reflecting lower energy and service costs.
  - Pelican Lake production averaged 44,779 bbl/d in 2024, a decrease of 5% from 2023 levels, reflecting low natural field declines from this long life low decline asset, partially offset by increased drilling activity in 2024.
    - Operating costs at Pelican Lake averaged $9.11/bbl (US$6.65/bbl) in 2024, an increase of 6% compared to 2023 levels, primarily reflecting lower volumes.
  - North America light crude oil and NGLs production averaged 114,370 bbl/d in 2024, an increase of 5% compared to 2023 levels, primarily driven by strong organic growth in liquids-rich natural gas as well as the recently acquired Duvernay assets.
    - Operating costs in the Company's North America light crude oil and NGLs operations averaged $13.55/bbl (US$9.89/bbl) in 2024, a decrease of 17% over 2023 levels, primarily reflecting higher volumes and lower energy costs.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Natural gas production (MMcf/d)	**2,273**	2,039	2,218	**2,136**	2,139
Net wells targeting natural gas	**14**	24	9	**79**	61
Net successful wells drilled	**14**	24	9	**78**	61
Success rate	**100%**	100%	100%	**99%**	100%

- North America natural gas annual production averaged 2,136 MMcf/d in 2024, comparable to 2023 levels. The Company remained focused on liquids-rich natural gas activity in the Montney and Deep Basin, while certain dry natural gas drilling activity in 2024 was deferred due to low natural gas prices.
  - Canadian Natural drilled a total of 79 net natural gas wells in 2024, 12 fewer than originally budgeted, as a result of the Company's strategic decision to reduce dry natural gas activity due to low natural gas prices.
    - North America natural gas operating costs averaged $1.19/Mcf in 2024, a 6% decrease compared to 2023 levels, primarily reflecting lower energy costs.

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Bitumen production (bbl/d)	**276,231**	271,551	278,422	**271,011**	262,000
Net wells targeting bitumen	**16**	25	—	**94**	50
Net successful wells drilled	**16**	25	—	**94**	50
Success rate	**100%**	100%	—%	**100%**	100%

- Record annual thermal in situ production of 271,011 bbl/d, an increase of 3% or approximately 9,000 bbl/d from 2023 levels as a result of the Company's capital efficient thermal pad add development program.
  - Annual thermal in situ operating costs were strong, averaging $11.04/bbl (US$8.06/bbl) in 2024, a decrease of 16% from 2023 levels, primarily reflecting lower energy costs and higher production volumes.
- 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 Wolf Lake, the Company brought a steam assisted gravity drainage ("SAGD") pad on production ahead of schedule in Q4/24, originally targeted for Q1/25.
  - At Primrose, the Company brought a CSS pad on production ahead of schedule in Q4/24, originally targeted for Q2/25. A second CSS pad has been drilled and is targeted to come on production ahead of schedule in late Q1/25, originally budgeted for Q2/25.
  - 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 is drilling two SAGD pads in the first half of 2025 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 is currently drilling a SAGD pad which is targeted to come on production in Q4/25 with a second SAGD pad targeted to be drilled in Q4/25 and come on production in Q4/26.
- 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. Results to-date have been positive with recent SOR reductions of approximately 30%, trending towards a targeted reduction of 40% to 50%. Solvent recoveries continue to meet expectations, exceeding 80%. The Company will continue to monitor SORs, solvent recovery and production trends.
  - 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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Synthetic crude oil production (bbl/d) (1)(2)	**534,631**	497,656	500,133	**472,245**	451,339

(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 2024, as follows:
  - Record annual Oil Sands Mining and Upgrading production of 472,245 bbl/d of SCO in 2024, an increase of 5% or approximately 21,000 bbl/d from 2023 levels.
    - Record quarterly production of 534,631 bbl/d of SCO was achieved in Q4/24, including planned turnaround activities. Quarterly production volumes increased 7% or approximately 34,500 bbl/d from Q4/23 levels.
      - At AOSP, the planned turnaround was successfully completed on October 18, 2024. Due to strong execution, the annual net production impact to AOSP from the planned turnaround was reduced to approximately 5,400 bbl/d, a significant improvement compared to the budgeted net production impact of 11,000 bbl/d.
  - Industry leading annual Oil Sands Mining and Upgrading operating costs of $22.88/bbl (US$16.70/bbl) of SCO were achieved in 2024, a decrease of 6% from 2023 levels. The decrease in 2024 operating costs compared to 2023 was due primarily to higher production volumes and lower energy costs.
  - Canadian Natural's high value SCO represented approximately 47% of the Company's total liquids volumes in 2024 and captured strong annual realized SCO pricing of $98.03/bbl in 2024, generating significant free cash flow.
- 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.
- A Debottleneck Project was completed at the Scotford Upgrader which increased gross capacity at AOSP by approximately 8,000 bbl/d to 328,000 bbl/d in October 2024.
- Subsequent to year end, Oil Sands Mining and Upgrading continued to achieve strong production and high utilization. In January 2025 and February 2025, production averaged on a gross basis approximately **634,000 bbl/d** over the two months. February 2025 was the highest monthly gross production in our history at approximately **640,000 bbl/d** as we focus on continuous improvement initiatives combined with strong performance from the Reliability Enhancement Project at Horizon and Debottleneck Project at the Scotford Upgrader.
  - Additionally, further value has been unlocked from piping modifications completed during the recent Debottleneck Project at the Scotford Upgrader. These modifications unlock approximately 5,000 bbl/d of annual gross production from the Albian mines, resulting in higher utilization during planned upgrader turnarounds. This increased zero decline production will continue to benefit Canadian Natural for decades, including our increased ownership in the Albian mines.
- As previously announced with the 2025 budget, the only planned turnaround in 2025 in the Oil Sands Mining and Upgrading operations is at AOSP, where the Scotford Upgrader is targeted to operate at reduced rates for 73 days, impacting net annual average production by approximately 31,000 bbl/d, based on Canadian Natural's current 90% working interest.
- 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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil production (bbl/d)	**23,411**	24,144	25,829	**24,070**	26,091
Natural gas production (MMcf/d)	**10**	10	13	**11**	12

- International E&P crude oil production volumes averaged 24,070 bbl/d in 2024, a decrease of 8% compared to 2023 levels primarily due to natural field declines.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) (1)	**$ 70.27**	$ 75.16	$ 78.33	**$ 75.72**	$ 77.61
WCS heavy differential (discount) to WTI (US$/bbl) (1)	**$ (12.55)**	$ (13.51)	$ (21.90)	**$ (14.73)**	$ (18.62)
WCS heavy differential as a percentage of WTI (%) (1)	**18%**	18%	28%	**19%**	24%
Condensate benchmark price (US$/bbl)	**$ 70.66**	$ 71.24	$ 76.22	**$ 72.94**	$ 76.55
SCO price (US$/bbl) (1)	**$ 71.13**	$ 76.51	$ 78.64	**$ 75.09**	$ 79.64
SCO premium (discount) to WTI (US$/bbl) (1)	**$ 0.86**	$ 1.35	$ 0.31	**$ (0.63)**	$ 2.03
AECO benchmark price (C$/GJ)	**$ 1.38**	$ 0.77	$ 2.52	**$ 1.36**	$ 2.77
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) (2)(3)(4)(5)	**$ 75.22**	$ 79.15	$ 69.39	**$ 77.76**	$ 72.36
SCO realized price (C$/bbl) (1)(3)(4)(5)	**$ 95.08**	$ 100.93	$ 98.73	**$ 98.03**	$ 100.06
Natural gas realized price (C$/Mcf) (4)	**$ 2.02**	$ 1.25	$ 2.80	**$ 1.86**	$ 3.10

(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 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 and year ended December 31, 2024 dated March 5, 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$75.72/bbl in 2024, a decrease of US$1.89/bbl compared to 2023, primarily reflecting weaker global demand growth and concerns of higher non-OPEC+ supply, partially offset by continued supply quota management by OPEC+, and geopolitical tensions in the Middle East.
- SCO pricing averaged US$75.09/bbl in 2024, representing a US$0.63/bbl price discount to WTI pricing, compared to a US$2.03/bbl price premium to WTI in 2023.
- The WCS differential to WTI averaged US$14.73/bbl, tightening by US$3.89/bbl in 2024, compared to US$18.62/bbl in 2023, primarily reflecting the start-up of the TMX pipeline in Q2/24, combined with stronger USGC heavy oil pricing.
- The North West Redwater ("NWR") refinery primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 77,742 bbl/d in Q4/24.
- During 2024, the Company increased its contracted crude oil transportation capacity to 256,500 bbl/d, expanding its committed volumes to Canada’s west coast and to the USGC to approximately 23% of its 2025 budgeted liquids production. The additional egress supports Canadian Natural’s long-term sales strategy by targeting expanded refining markets, driving stronger netbacks while also reducing exposure to egress constraints.

- In December 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d, further expanding access to Canada's west coast.
- In Q1/24, the Company increased its total committed capacity on the Flanagan South pipeline to 77,500 bbl/d, an incremental 55,000 bbl/d, further expanding the Company's heavy oil diversification and market access to the USGC.
- The Company also has committed capacity of 10,000 bbl/d on the Keystone Base pipeline, with direct access to the USGC.

▪ AECO natural gas prices averaged $1.36/GJ in 2024, significantly lower compared to 2023, reflecting high storage inventories resulting from weaker demand and increased production levels in the WCSB, combined with lower NYMEX benchmark pricing.

- 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.

CORPORATE UPDATE

One of Canadian Natural's many strengths is our strong and deep leadership team. The Company takes a very proactive disciplined approach to succession, with well-planned and successful transitions, ensuring we maintain our strong corporate culture and top tier performance.

As part of ongoing management succession on April 30th, 2025, Mark Stainthorpe, Chief Financial Officer will become Executive Advisor, Finance and Victor Darel, currently Senior Vice President, Finance and Principal Accounting Officer will be promoted to Chief Financial Officer and Principal Accounting Officer.

Victor Darel is a Chartered Professional Accountant and has over 20 years of Finance and Accounting experience in both the public and private sectors. Victor has been with Canadian Natural for 11 years with increasing responsibilities in his roles over that time including as Senior Vice President, Finance and Principal Accounting Officer.

Mark Stainthorpe will continue to work together with the Finance and Investor Relations teams in his new role as Executive Advisor.

Sheryl Kapeluck, Vice President, Finance, Corporate will be promoted to the role of Senior Vice President, Finance and will join the Management Committee. Sheryl is a Chartered Professional Accountant with over 25 years of professional experience and has been with Canadian Natural for 14 years.

Scott Stauth, commenting on the succession stated, "Both Victor and Sheryl have brought a significant amount of expertise to their current roles, and we look forward to the contributions they will be making in their new positions as CFO and SVP Finance respectively. We thank Mark for his 6 years as our CFO and for the leadership Mark has provided as a key member of our Management Committee."

2024 YEAR END RESERVES

Determination of Reserves

For the year ended December 31, 2024, the Company retained IQREs, Sproule International Limited and GLJ Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with the IQREs as to the Company's reserves.

Additional reserves information is disclosed in the Company's Annual Information Form.

Summary of Company Gross Reserves

As of December 31, 2024
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Bitumen (Thermal Oil) (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
Total Company								
Proved								
Developed Producing	118	123	202	631	7,567	5,034	172	9,652
Developed Non-Producing	5	7	—	78	—	246	9	140
Undeveloped	129	88	53	2,603	96	11,625	533	5,440
Total Proved	252	219	255	3,312	7,663	16,904	713	15,231
Probable	94	99	105	1,878	593	10,252	403	4,879
Total Proved plus Probable	346	318	360	5,190	8,255	27,156	1,116	20,110

Notes to Reserves:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and natural gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the Independent Qualified Reserves Evaluators in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule International Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2024:

		2025	2026	2027	2028	2029
Crude Oil and NGLs						
WTI	US$/bbl	71.58	74.48	75.81	77.66	79.22
WCS	C$/bbl	82.69	84.27	83.81	85.70	87.45
Canadian Light Sweet	C$/bbl	94.79	97.04	97.37	99.80	101.79
Cromer LSB	C$/bbl	93.30	96.05	95.92	98.55	100.51
Edmonton C5+	C$/bbl	100.14	100.72	100.24	102.73	104.79
Brent	US$/bbl	75.58	78.51	79.89	81.82	83.46
AECO	C$/MMBtu	2.36	3.33	3.48	3.69	3.76
BC Westcoast Station 2	C$/MMBtu	2.15	3.14	3.29	3.50	3.57
Henry Hub	US$/MMBtu	3.31	3.73	3.85	3.93	4.01

All prices increase at a rate of 2% per year after 2029.

A US$/C$ foreign exchange rate of 0.7117 was used for 2025, 0.7283 for 2026, and 0.7433 for 2027 and thereafter in the year end 2024 evaluation.

4. A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel 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.

5. Oil and natural gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2025 proved developed producing production forecast prepared by the IQREs.
9. Finding, Development and Acquisition ("FD&A") costs excluding changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2024 by the sum of total additions and revisions for the relevant reserves category.
10. FD&A costs including changes in FDC are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2024 and net changes in FDC from December 31, 2023 to December 31, 2024 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation costs.
11. Abandonment, decommissioning and reclamation ("ADR") costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's total Asset Retirement Obligation ("ARO"), before inflation and discounting, for development existing as at December 31, 2024 and forecast estimates of ADR costs attributable to future development activity.

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 or cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP and other financial measures. The non-GAAP and other financial measures used by the Company may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the Company's financial statements, as applicable, as an indication of the Company's performance. Descriptions of the Company's non-GAAP and other financial measures included in this 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 and year ended December 31, 2024, dated March 5, 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 year ended December 31, 2024 is shown below:

($ millions)	Year Ended **Dec 31 2024**
Adjusted funds flow [1]	**$ 14,859**
Less: Dividends on common shares	**4,429**
Net capital expenditures,[2] excluding net acquisition costs	**5,286**
Abandonment expenditures	**646**
Free cash flow	**$ 4,498**

(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 and year ended December 31, 2024, dated March 5, 2025.

(2) Net Capital expenditures is a Non-GAAP Financial Measure. 2024 Net capital expenditures, excluding net acquisition costs is equal to net capital expenditures of $14,431 million less net acquisition costs of $9,145 million in the period. Refer to the "Non-GAAP and Other Financial Measures" section of the Company's MD&A for the three months and year ended December 31, 2024, dated March 5, 2025.

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)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023
Long-term debt	**$ 18,819**	$ 10,029	$ 10,799
Less: cash and cash equivalents	**131**	721	877
Long-term debt, net	**$ 18,688**	$ 9,308	$ 9,922

Break-even WTI Price

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

Capital Budget

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

The 2025 capital budget reflects budgeted net capital expenditures, before capital related to the office relocation and 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, the impact of the Russian invasion of 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 the tariffs on a variety of goods announced by the US government on March 4, 2025 and Canadian countermeasures subsequently announced, both of which are anticipated to evolve); 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, including the acquired working interests in AOSP and Duvernay assets from Chevron Canada Limited ("Chevron") in December 2024; 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 the tariffs on a variety of goods announced by the US government on March 4, 2025 and Canadian countermeasures subsequently announced, both of which are anticipated to evolve), 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 and year ended December 31, 2024, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2023. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months and year ended December 31, 2024 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 and year ended December 31, 2024 in relation to the comparable periods in 2023 and the third 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, 2023, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at 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 March 5, 2025.

FINANCIAL HIGHLIGHTS[1]

	Three Months Ended			Year Ended	
($ millions, except per common share amounts)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Product sales [1]	**$ 11,064**	$ 10,401	$ 10,679	**$ 41,509**	$ 40,835
Crude oil and NGLs	**$ 10,381**	$ 9,943	$ 9,829	**$ 39,084**	$ 37,300
Natural gas	**$ 451**	$ 257	$ 603	**$ 1,568**	$ 2,575
Net earnings	**$ 1,138**	$ 2,266	$ 2,627	**$ 6,106**	$ 8,233
Per common share – basic	**$ 0.54**	$ 1.07	$ 1.22	**$ 2.87**	$ 3.77
– diluted	**$ 0.54**	$ 1.06	$ 1.21	**$ 2.85**	$ 3.74
Adjusted net earnings from operations [2]	**$ 1,977**	$ 2,071	$ 2,546	**$ 7,414**	$ 8,533
Per common share – basic [3]	**$ 0.94**	$ 0.98	$ 1.18	**$ 3.49**	$ 3.91
– diluted [3]	**$ 0.93**	$ 0.97	$ 1.17	**$ 3.46**	$ 3.87
Cash flows from operating activities	**$ 3,432**	$ 3,002	$ 4,815	**$ 13,386**	$ 12,353
Adjusted funds flow [2]	**$ 4,186**	$ 3,921	$ 4,419	**$ 14,859**	$ 15,274
Per common share – basic [3]	**$ 1.99**	$ 1.85	$ 2.05	**$ 6.99**	$ 7.00
– diluted [3]	**$ 1.97**	$ 1.84	$ 2.03	**$ 6.94**	$ 6.93
Cash flows used in investing activities	**$ 10,414**	$ 1,274	$ 946	**$ 14,095**	$ 4,858
Net capital expenditures [4]	**$ 10,348**	$ 1,349	$ 975	**$ 14,431**	$ 4,909
Abandonment expenditures	**$ 151**	$ 204	$ 149	**$ 646**	$ 509

(1) Further details related to product sales are disclosed in note 18 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 and 2023 and has been updated for all periods presented. 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 year ended December 31, 2024 were $6,106 million compared with $8,233 million for the year ended December 31, 2023. Net earnings for the year ended December 31, 2024 included non-operating losses, net of tax, of $1,308 million compared with non-operating losses of $300 million for the year ended December 31, 2023 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on the repayment of US dollar debt securities, the gain from investments, a recoverability charge related to the notice to withdraw from Block 11B/12B in South Africa in 2024, and a recoverability charge related to the increase in estimate of the future abandonment costs for the Ninian field in the North Sea in 2024 and 2023. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2024 were $7,414 million compared with $8,533 million for the year ended December 31, 2023.

Net earnings for the fourth quarter of 2024 were $1,138 million compared with $2,627 million for the fourth quarter of 2023 and $2,266 million for the third quarter of 2024. Net earnings for the fourth quarter of 2024 included non-operating losses, net of tax, of $839 million compared with non-operating income of $81 million for the fourth quarter of 2023 and non-operating income of $195 million for the third quarter of 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, the loss 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 and 2023. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2024 were $1,977 million compared with $2,546 million for the fourth quarter of 2023 and $2,071 million for the third quarter of 2024.

(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.

The decrease in net earnings and adjusted net earnings from operations for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected:

- lower realized natural gas pricing in the North America Exploration and Production segment; and
- lower netbacks(1) in the Oil Sands Mining and Upgrading segment;

partially offset by:

- higher realized crude oil and NGLs pricing(1) in the North America Exploration and Production segment; and
- higher SCO sales volumes in the Oil Sands Mining and Upgrading segment.

The decrease in net earnings and adjusted net earnings from operations for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected:

- lower realized SCO pricing(1) in the Oil Sands Mining and Upgrading segment; and
- lower realized crude oil and NGLs pricing in the North America Exploration and Production segment;

partially offset by:

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

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange loss (gain), and the loss (gain) from investments also contributed to the decrease in net earnings. 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 year ended December 31, 2024 were $13,386 million compared with $12,353 million for the year ended December 31, 2023. Cash flows from operating activities for the fourth quarter of 2024 were $3,432 million compared with $4,815 million for the fourth quarter of 2023, and $3,002 million for the third quarter of 2024. The fluctuations in cash flows from operating activities from the comparable periods was 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 year ended December 31, 2024 was $14,859 million compared with $15,274 million for the year ended December 31, 2023. Adjusted funds flow for the fourth quarter of 2024 was $4,186 million compared with $4,419 million for the fourth quarter of 2023, and $3,921 million for the third quarter of 2024. The fluctuations in adjusted funds flow from the comparable periods was 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 fourth quarter of 2024 of 1,090,002 bbl/d increased 4% from 1,047,541 bbl/d for the fourth quarter of 2023 and increased 7% from 1,021,572 bbl/d for the third quarter of 2024. Natural gas production before royalties for the fourth quarter of 2024 of 2,283 MMcf/d was comparable with 2,231 MMcf/d for the fourth quarter of 2023 and increased 11% from 2,049 MMcf/d for the third quarter of 2024. Total production before royalties for the fourth quarter of 2024 of 1,470,428 BOE/d increased 4% from 1,419,313 BOE/d for the fourth quarter of 2023 and increased 8% from 1,363,086 BOE/d for the third 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.

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

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices averaged $75.22 per bbl for the fourth quarter of 2024, an increase of 8% from $69.39 per bbl for the fourth quarter of 2023 and a decrease of 5% from $79.15 per bbl for the third quarter of 2024. The realized natural gas price decreased 28% to average $2.02 per Mcf for the fourth quarter of 2024 from $2.80 per Mcf for the fourth quarter of 2023, and increased 62% from $1.25 per Mcf for the third quarter of 2024. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 4% to average $95.08 per bbl for the fourth quarter of 2024 from $98.73 per bbl for the fourth quarter of 2023, and decreased 6% from $100.93 per bbl for the third quarter of 2024. The Company's realized pricing reflected 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[(1)] averaged $13.15 per bbl for the fourth quarter of 2024, a decrease of 13% from $15.05 per bbl for the fourth quarter of 2023 and a decrease of 10% from $14.65 per bbl for the third quarter of 2024. Natural gas production expense[(1)] averaged $1.12 per Mcf for the fourth quarter of 2024, comparable with $1.13 per Mcf for the fourth quarter of 2023, and a decrease of 11% from $1.26 per Mcf for the third quarter of 2024. In the Oil Sands Mining and Upgrading segment, production expense[(1)] averaged $20.97 per bbl for the fourth quarter of 2024, comparable with $20.96 per bbl for the fourth quarter of 2023 and $20.67 per bbl for the third 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.

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)		**Dec 31 2024**		Sep 30 2024		Jun 30 2024		Mar 31 2024
Product sales [(1)]	**$**	**11,064**	$	10,401	$	10,622	$	9,422
Crude oil and NGLs	**$**	**10,381**	$	9,943	$	10,084	$	8,676
Natural gas	**$**	**451**	$	257	$	331	$	529
Net earnings	**$**	**1,138**	$	2,266	$	1,715	$	987
Net earnings per common share [(2)]								
– basic	**$**	**0.54**	$	1.07	$	0.80	$	0.46
– diluted	**$**	**0.54**	$	1.06	$	0.80	$	0.46

($ millions, except per common share amounts)		Dec 31 2023		Sep 30 2023		Jun 30 2023		Mar 31 2023
Product sales [(1)]	$	10,679	$	11,762	$	8,846	$	9,548
Crude oil and NGLs	$	9,829	$	10,944	$	8,115	$	8,412
Natural gas	$	603	$	599	$	522	$	851
Net earnings	$	2,627	$	2,344	$	1,463	$	1,799
Net earnings per common share [(2)]								
– basic	$	1.22	$	1.08	$	0.67	$	0.82
– diluted	$	1.21	$	1.06	$	0.66	$	0.81

(1) Further details related to product sales for the three months ended December 31, 2024 and 2023 are disclosed in note 18 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.

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

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 Russian invasion of Ukraine and conflict in the Middle East) 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 from Chevron in the fourth quarter of 2024, and 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 from Chevron 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.
- **Loss (gain) from investments** – Fluctuations due to the loss (gain) from the Company's investment in PrairieSky Royalty Ltd. shares.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing declined in the fourth quarter of 2024 as a result of weaker global demand growth and concerns of higher non-OPEC+ supply, partially offset by continued supply quota management by OPEC+ and geopolitical tensions in the Middle East. The start-up of the TMX pipeline in the second quarter of 2024 contributed to a narrowing of the WCS differential with benefit to the Company's realized product pricing in 2024. Natural gas prices remained low as a result of higher storage levels in 2024 but recovered slightly during the fourth quarter due to seasonal demand factors and increased exports.

On March 4, 2025, the US government implemented 10% tariffs on energy products and 25% tariffs on other Canadian goods imported into the United States, with countermeasures subsequently announced by the Canadian government. The effect of these actions may have an impact on the market and 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. At this time, the duration and impact of these trade actions remains uncertain. The Company will continue to assess the impacts of the tariffs on its business, financial condition and results.

Liquidity

As at December 31, 2024, the Company had undrawn revolving bank credit facilities of $4,562 million. Including cash and cash equivalents, the Company had approximately $4,693 million in liquidity[(1)]. The Company also has certain other dedicated credit facilities supporting letters of credit.

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

Capital Spending

On January 9, 2025, the Company announced its 2025 operating capital budget[(2)] 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.

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 (Non-GAAP Financial Measure). Refer to the "Advisory" section of this MD&A for further details on forward-looking statements.

Benchmark Commodity Prices

	Three Months Ended			Year Ended	
(Average for the period)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
WTI benchmark price (US$/bbl)	**$ 70.27**	$ 75.16	$ 78.33	**$ 75.72**	$ 77.61
Dated Brent benchmark price (US$/bbl)	**$ 74.69**	$ 80.25	$ 84.06	**$ 80.75**	$ 82.61
WCS Heavy Differential from WTI (US$/bbl)	**$ 12.55**	$ 13.51	$ 21.90	**$ 14.73**	$ 18.62
SCO price (US$/bbl)	**$ 71.13**	$ 76.51	$ 78.64	**$ 75.09**	$ 79.64
Condensate benchmark price (US$/bbl)	**$ 70.66**	$ 71.24	$ 76.22	**$ 72.94**	$ 76.55
NYMEX benchmark price (US$/MMBtu)	**$ 2.79**	$ 2.16	$ 2.87	**$ 2.27**	$ 2.74
AECO benchmark price (C$/GJ)	**$ 1.38**	$ 0.77	$ 2.52	**$ 1.36**	$ 2.77
US/Canadian dollar average exchange rate (US$)	**$ 0.7151**	$ 0.7332	$ 0.7341	**$ 0.7300**	$ 0.7409

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

(2) 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.

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$75.72 per bbl for the year ended December 31, 2024, comparable with US$77.61 per bbl for the year ended December 31, 2023. WTI averaged US$70.27 per bbl for the fourth quarter of 2024, a decrease of 10% from US$78.33 per bbl for the fourth quarter of 2023 and a decrease of 7% from US$75.16 per bbl for the third quarter of 2024.

Crude oil sales contracts for the Company's International segments are typically based on Brent pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$80.75 per bbl for the year ended December 31, 2024, comparable with US$82.61 per bbl for the year ended December 31, 2023. Brent averaged US$74.69 per bbl for the fourth quarter of 2024, a decrease of 11% from US$84.06 per bbl for the fourth quarter of 2023 and a decrease of 7% from US$80.25 per bbl for the third quarter of 2024.

The decrease in WTI and Brent benchmark pricing for the three months and year ended December 31, 2024 from the comparable periods primarily reflected weaker global demand growth and concerns of higher non-OPEC+ supply, partially offset by continued supply quota management by OPEC+, and geopolitical tensions in the Middle East.

The WCS Heavy Differential averaged US$14.73 per bbl for the year ended December 31, 2024 compared with US$18.62 per bbl for the year ended December 31, 2023. The WCS Heavy Differential averaged US$12.55 per bbl for the fourth quarter of 2024 compared with US$21.90 per bbl for the fourth quarter of 2023 and US$13.51 per bbl for the third quarter of 2024. The narrowing of the WCS Differential for the three months and year ended December 31, 2024 from the comparable periods in 2023 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 narrowing of the WCS Heavy Differential for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected increased refinery capacity following planned and unplanned outages in the US Midwest in the third quarter of 2024, as well as strengthening US Gulf Coast heavy oil pricing.

The SCO price averaged US$75.09 per bbl for the year ended December 31, 2024, a decrease of 6% from US$79.64 per bbl for the year ended December 31, 2023. The SCO price averaged US$71.13 per bbl for the fourth quarter of 2024, a decrease of 10% from US$78.64 per bbl for the fourth quarter of 2023 and a decrease of 7% from US$76.51 per bbl for the third quarter of 2024. The decrease in SCO pricing for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected weaker diesel pricing, together with increased production in the Western Canadian Sedimentary Basin ("WCSB") in 2024. The decrease in SCO pricing for the fourth quarter of 2024 from the comparable periods primarily reflected WTI benchmark pricing.

NYMEX natural gas prices averaged US$2.27 per MMBtu for the year ended December 31, 2024, a decrease of 17% from US$2.74 per MMBtu for the year ended December 31, 2023. NYMEX natural gas prices averaged US$2.79 per MMBtu for the fourth quarter of 2024, comparable with US$2.87 per MMBtu for the fourth quarter of 2023 and an increase of 29% from US$2.16 per MMBtu for the third quarter of 2024. The decrease in NYMEX natural gas prices for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected high North American and European inventory levels resulting from weaker demand following mild winter weather in 2024. The increase in NYMEX natural gas pricing for the fourth quarter of 2024 from the third quarter of 2024 reflected seasonal demand factors, increased LNG exports out of the US Gulf Coast, and lower US production levels.

AECO natural gas prices averaged $1.36 per GJ for the year ended December 31, 2024, a decrease of 51% from $2.77 per GJ for the year ended December 31, 2023. AECO natural gas prices averaged $1.38 per GJ for the fourth quarter of 2024, a decrease of 45% from $2.52 per GJ for the fourth quarter of 2023 and an increase of 79% from $0.77 per GJ for the third quarter of 2024. The decrease in AECO natural gas prices for the three months and year ended December 31, 2024 from the comparable periods in 2023 reflected high storage inventories resulting from weaker demand and increased production levels in the WCSB, combined with weaker NYMEX benchmark pricing. The increase in AECO natural gas prices for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected increased exports out of the WCSB, seasonal demand factors, and stronger NYMEX benchmark pricing.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**531,960**	499,772	521,579	**509,288**	496,100
North America – Oil Sands Mining and Upgrading [(1)]	**534,631**	497,656	500,133	**472,245**	451,339
International – Exploration and Production					
North Sea	**11,467**	10,958	12,616	**11,536**	12,639
Offshore Africa	**11,944**	13,186	13,213	**12,534**	13,452
Total International [(2)]	**23,411**	24,144	25,829	**24,070**	26,091
Total Crude oil and NGLs	**1,090,002**	1,021,572	1,047,541	**1,005,603**	973,530
Natural gas (MMcf/d) [(3)]					
North America	**2,273**	2,039	2,218	**2,136**	2,139
International					
North Sea	**4**	1	2	**2**	2
Offshore Africa	**6**	9	11	**9**	10
Total International	**10**	10	13	**11**	12
Total Natural gas	**2,283**	2,049	2,231	**2,147**	2,151
Total Barrels of oil equivalent (BOE/d)	**1,470,428**	1,363,086	1,419,313	**1,363,496**	1,332,105
Product mix					
Light and medium crude oil and NGLs	**10%**	9%	10%	**10%**	10%
Pelican Lake heavy crude oil	**3%**	3%	3%	**3%**	3%
Primary heavy crude oil	**6%**	6%	6%	**6%**	6%
Bitumen (thermal oil)	**19%**	20%	20%	**20%**	20%
Synthetic crude oil [(1)]	**36%**	37%	35%	**35%**	34%
Natural gas	**26%**	25%	26%	**26%**	27%
Percentage of product sales [(1) (4) (5)]					
Crude oil and NGLs	**96%**	97%	94%	**96%**	93%
Natural gas	**4%**	3%	6%	**4%**	7%

(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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**425,682**	399,397	431,091	**408,237**	406,534
North America – Oil Sands Mining and Upgrading (1)	**432,701**	408,120	443,535	**386,171**	385,996
International – Exploration and Production					
North Sea	**11,441**	10,925	12,590	**11,509**	12,609
Offshore Africa	**11,364**	12,496	11,917	**11,918**	12,183
Total International	**22,805**	23,421	24,507	**23,427**	24,792
Total Crude oil and NGLs	**881,188**	830,938	899,133	**817,835**	817,322
Natural gas (MMcf/d)					
North America	**2,223**	2,016	2,148	**2,091**	2,055
International					
North Sea	**4**	1	2	**2**	2
Offshore Africa	**6**	9	11	**9**	10
Total International	**10**	10	13	**11**	12
Total Natural gas	**2,233**	2,026	2,161	**2,102**	2,067
Total Barrels of oil equivalent (BOE/d)	**1,253,347**	1,168,599	1,259,297	**1,168,209**	1,161,852

(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.

Record crude oil and NGLs production before royalties for the year ended December 31, 2024 averaged 1,005,603 bbl/d, an increase of 3% from 973,530 bbl/d for the year ended December 31, 2023. Record crude oil and NGLs production before royalties for the fourth quarter of 2024 averaged 1,090,002 bbl/d, an increase of 4% from 1,047,541 bbl/d for the fourth quarter of 2023 and an increase of 7% from 1,021,572 bbl/d for the third quarter of 2024. The increase in crude oil and NGLs production before royalties for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected high utilization in the Oil Sands Mining and Upgrading segment, combined with strong drilling results in the North America Exploration and Production segment. The increase in crude oil and NGLs production for the fourth quarter of 2024 from the fourth quarter of 2023 primarily reflected the acquisition of Chevron's assets in December 2024, combined with high utilization in the Oil Sands Mining and Upgrading segment. The increase in crude oil and NGLs production for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected the acquisition of Chevron's assets in December 2024, combined with high utilization in the Oil Sands Mining and Upgrading segment including the completion of the planned turnaround and debottleneck project at the non-operated Scotford Upgrader ("Scotford"), strong drilling results and the cyclical nature of Primrose in the North America Exploration and Production segment.

Annual crude oil and NGLs production for 2024 was within the Company's previously issued production target of 977,000 bbl/d and 1,008,000 bbl/d. 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 year ended December 31, 2024 averaged 2,147 MMcf/d, comparable with 2,151 MMcf/d for the year ended December 31, 2023. Natural gas production before royalties for the fourth quarter of 2024 averaged 2,283 MMcf/d, comparable with 2,231 MMcf/d for the fourth quarter of 2023 and an increase of 11% from 2,049 MMcf/d for the third quarter of 2024. The increase in natural gas production before royalties for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected strong drilling results and the acquisition of Chevron's assets in December 2024.

Annual natural gas production for 2024 was within the Company's previously issued production target of 2,120 MMcf/d and 2,230 MMcf/d. 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

Record North America crude oil and NGLs production before royalties for the year ended December 31, 2024 averaged 509,288 bbl/d, an increase of 3% from 496,100 bbl/d for the year ended December 31, 2023. North America crude oil and NGLs production before royalties for the fourth quarter of 2024 of 531,960 bbl/d was comparable with 521,579 bbl/d for the fourth quarter of 2023 and increased 6% from 499,772 bbl/d for the third quarter of 2024. The increase in North America crude oil and NGLs production for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected increased production from thermal oil pad additions, and strong drilling results for liquids-rich natural gas and heavy oil, partially offset by natural field declines. The increase in North America crude oil and NGLs production for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected the acquisition of Chevron's assets in December 2024, combined with strong drilling results for liquids-rich natural gas and heavy oil, and the cyclical nature of Primrose.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 276,231 bbl/d for the fourth quarter of 2024, comparable with 278,422 bbl/d for the fourth quarter of 2023 and 271,551 bbl/ d for the third quarter of 2024.

Pelican Lake heavy crude oil production before royalties for the fourth quarter of 2024 averaged 44,035 bbl/d, a decrease of 4% from 46,046 bbl/d for the fourth quarter of 2023 reflecting Pelican Lake's long life low decline, and comparable with 45,101 bbl/d for the third quarter of 2024, reflecting drilling completed in the first half of 2024.

North America natural gas production before royalties for the year ended December 31, 2024 averaged 2,136 MMcf/d, comparable with 2,139 MMcf/d for the year ended December 31, 2023. Natural gas production before royalties averaged 2,273 MMcf/d for the fourth quarter of 2024, comparable with 2,218 MMcf/d for the fourth quarter of 2023 and an increase of 11% from 2,039 MMcf/d for the third quarter of 2024. The increase in natural gas production for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected strong drilling results and the acquisition of Chevron's assets in December 2024.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the year ended December 31, 2024 averaged 472,245 bbl/d, an increase of 5% from 451,339 bbl/d for the year ended December 31, 2023. Record SCO production before royalties for the fourth quarter of 2024 averaged 534,631 bbl/d, an increase of 7% from 500,133 bbl/d for the fourth quarter of 2023 and an increase of 7% from 497,656 bbl/d for the third quarter of 2024. The increase in SCO production for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected strong performance and utilization at Horizon following the completion of the reliability enhancement project, and the acquisition of Chevron's assets in December 2024 at AOSP. The increase in SCO production for the fourth quarter of 2024 from the comparable periods primarily reflected the acquisition of Chevron's assets in December 2024, and high utilization at Horizon and AOSP following the completion of the planned turnaround and debottleneck project at Scotford.

International – Exploration and Production

International crude oil and NGLs production before royalties for the year ended December 31, 2024 averaged 24,070 bbl/d, a decrease of 8% from 26,091 bbl/d for the year ended December 31, 2023. International crude oil and NGLs production before royalties for the fourth quarter of 2024 averaged 23,411 bbl/d, a decrease of 9% from 25,829 bbl/d for the fourth quarter of 2023 and a decrease of 3% from 24,144 bbl/d for the third quarter of 2024. The decrease in International crude oil and NGLs production for the three months and year ended December 31, 2024 from the comparable periods reflected natural field declines.

International Crude Oil Inventory Volumes

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

(bbl)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023
International	**1,051,540**	655,729	515,543

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 75.22**	$ 79.15	$ 69.39	**$ 77.76**	$ 72.36
Transportation (2)	**6.08**	5.26	3.83	**5.50**	4.23
Realized price, net of transportation (2)	**69.14**	73.89	65.56	**72.26**	68.13
Royalties (3)	**14.77**	15.05	11.38	**14.85**	12.55
Production expense (4)	**13.15**	14.65	15.05	**14.72**	16.12
Netback (2)	**$ 41.22**	$ 44.19	$ 39.13	**$ 42.69**	$ 39.46
Natural gas ($/Mcf) (1)					
Realized price (5)	**$ 2.02**	$ 1.25	$ 2.80	**$ 1.86**	$ 3.10
Transportation (6)	**0.59**	0.63	0.54	**0.62**	0.56
Realized price, net of transportation	**1.43**	0.62	2.26	**1.24**	2.54
Royalties (3)	**0.04**	0.02	0.09	**0.05**	0.13
Production expense (4)	**1.12**	1.26	1.13	**1.22**	1.30
Netback (7)	**$ 0.27**	$ (0.66)	$ 1.04	**$ (0.03)**	$ 1.11
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 49.54**	$ 50.36	$ 48.41	**$ 50.82**	$ 50.54
Transportation (2)	**5.06**	4.67	3.61	**4.78**	3.88
Realized price, net of transportation (2)	**44.48**	45.69	44.80	**46.04**	46.66
Royalties (3)	**8.85**	9.05	7.05	**8.96**	7.77
Production expense (4)	**10.53**	11.81	11.75	**11.73**	12.74
Netback (2)	**$ 25.10**	$ 24.83	$ 26.00	**$ 25.35**	$ 26.15

(1) For crude oil and NGLs and BOE sales volumes, refer to the "Non-GAAP and Other Financial Measures" section of this MD&A. For natural gas sales volumes, refer to the "Daily Production, before royalties" section of this MD&A.
(2) Non-GAAP Ratio. Refer to the "Non-GAAP and Other Financial Measures" section of this MD&A.
(3) Calculated as royalties divided by respective sales volumes.
(4) Calculated as production expense divided by respective sales volumes.
(5) Calculated as natural gas sales divided by natural gas sales volumes.
(6) Calculated as natural gas transportation expense divided by natural gas sales volumes.
(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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs ($/bbl) [1]					
North America [2]	**$ 74.46**	$ 77.29	$ 66.69	**$ 76.37**	$ 70.51
International average [3]	**$ 96.36**	$ 109.41	$ 112.22	**$ 108.80**	$ 107.46
North Sea [3]	**$ 103.80**	$ 112.54	$ 118.50	**$ 111.53**	$ 110.99
Offshore Africa [3]	**$ 86.93**	$ 108.04	$ 107.88	**$ 106.00**	$ 106.25
Crude oil and NGLs average [2]	**$ 75.22**	$ 79.15	$ 69.39	**$ 77.76**	$ 72.36
Natural gas ($/Mcf) [1] [3]					
North America	**$ 1.98**	$ 1.19	$ 2.75	**$ 1.81**	$ 3.04
International average	**$ 11.28**	$ 12.67	$ 12.15	**$ 12.01**	$ 12.81
North Sea	**$ 8.87**	$ 11.28	$ 9.66	**$ 9.93**	$ 10.45
Offshore Africa	**$ 12.62**	$ 12.87	$ 12.51	**$ 12.46**	$ 13.19
Natural gas average	**$ 2.02**	$ 1.25	$ 2.80	**$ 1.86**	$ 3.10
Average ($/BOE) [1] [2]	**$ 49.54**	$ 50.36	$ 48.41	**$ 50.82**	$ 50.54

(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 increased 8% to average $76.37 per bbl for the year ended December 31, 2024 from $70.51 per bbl for the year ended December 31, 2023. North America realized crude oil and NGLs prices averaged $74.46 per bbl for the fourth quarter of 2024, an increase of 12% from $66.69 per bbl for the fourth quarter of 2023 and a decrease of 4% from $77.29 per bbl for the third quarter of 2024. The increase in North America realized crude oil and NGLs prices per bbl for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected the narrowing of the WCS Heavy Differential. The decrease in North America realized crude oil and NGLs prices per bbl for the fourth quarter of 2024 from the third quarter of 2024 reflected lower WTI benchmark pricing. The Company continues to focus on its crude oil blending marketing strategy and in the fourth quarter of 2024 contributed approximately 194,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices decreased 40% to average $1.81 per Mcf for the year ended December 31, 2024 from $3.04 per Mcf for the year ended December 31, 2023. North America realized natural gas prices decreased 28% to average $1.98 per Mcf for the fourth quarter of 2024 from $2.75 per Mcf for the fourth quarter of 2023, and increased 66% from $1.19 per Mcf for the third quarter of 2024. The decrease in North America realized natural gas prices per Mcf for the three months and year ended December 31, 2024 from the comparable periods in 2023 reflected lower AECO benchmark pricing. The increase for the fourth quarter of 2024 from the third quarter of 2024 reflected higher AECO and export pricing.

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

	Three Months Ended		
(Quarterly average)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 68.63**	$ 67.58	$ 69.42
Pelican Lake heavy crude oil ($/bbl)	**$ 79.88**	$ 84.02	$ 73.47
Primary heavy crude oil ($/bbl)	**$ 78.34**	$ 83.56	$ 72.90
Bitumen (thermal oil) ($/bbl)	**$ 75.11**	$ 78.26	$ 62.64
Natural gas ($/Mcf)	**$ 1.98**	$ 1.19	$ 2.75

(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 averaged $108.80 per bbl for the year ended December 31, 2024, comparable with $107.46 per bbl for the year ended December 31, 2023. International realized crude oil and NGLs prices decreased 14% to average $96.36 per bbl for the fourth quarter of 2024 from $112.22 per bbl for the fourth quarter of 2023, and decreased 12% from $109.41 per bbl for the third 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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 15.22**	$ 15.72	$ 11.72	**$ 15.40**	$ 12.89
International average	**$ 1.99**	$ 4.02	$ 5.83	**$ 2.75**	$ 5.99
North Sea	**$ 0.23**	$ 0.33	$ 0.24	**$ 0.26**	$ 0.33
Offshore Africa	**$ 4.22**	$ 5.65	$ 10.58	**$ 5.30**	$ 10.08
Crude oil and NGLs average	**$ 14.77**	$ 15.05	$ 11.38	**$ 14.85**	$ 12.55
Natural gas ($/Mcf) (1)					
North America	**$ 0.04**	$ 0.01	$ 0.09	**$ 0.04**	$ 0.13
Offshore Africa	**$ 0.58**	$ 0.59	$ 0.59	**$ 0.57**	$ 0.62
Natural gas average	**$ 0.04**	$ 0.02	$ 0.09	**$ 0.05**	$ 0.13
Average ($/BOE) (1)	**$ 8.85**	$ 9.05	$ 7.05	**$ 8.96**	$ 7.77

(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 three months and year ended December 31, 2024 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates(1) averaged approximately 20% of product sales for the year ended December 31, 2024 compared with 18% of product sales for the year ended December 31, 2023. Crude oil and NGLs royalty rates averaged approximately 20% of product sales for the fourth quarter of 2024 compared with 18% for the fourth quarter of 2023 and 20% for the third quarter of 2024. The increase in royalty rates for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected increased realized heavy oil and bitumen pricing in 2024.

Natural gas royalty rates averaged approximately 2% of product sales for the year ended December 31, 2024 compared with 4% of product sales for the year ended December 31, 2023. Natural gas royalty rates averaged approximately 2% of product sales for the fourth quarter of 2024 compared with 3% for the fourth quarter of 2023 and 1% for the third quarter of 2024. The fluctuations in royalty rates for the three months and year ended December 31, 2024 from the comparable periods primarily reflected prevailing 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 5% for the year ended December 31, 2024 compared with 9% of product sales for the year ended December 31, 2023. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2024 compared with 9% of product sales for the fourth quarter of 2023 and 5% for the third quarter of 2024. The decrease in royalty rates as a percentage of product sales for the three months and year ended December 31, 2024 from the comparable periods in 2023 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			Year Ended	
	Dec 31 2024	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 10.83**	$ 12.36	$ 12.56	**$ 12.55**	$ 14.46
International average	**$ 77.66**	$ 52.04	$ 54.95	**$ 62.99**	$ 48.16
North Sea	**$ 118.91**	$ 120.92	$ 92.28	**$ 103.28**	$ 85.57
Offshore Africa	**$ 25.34**	$ 21.67	$ 23.25	**$ 21.77**	$ 21.14
Crude oil and NGLs average	**$ 13.15**	$ 14.65	$ 15.05	**$ 14.72**	$ 16.12
Natural gas ($/Mcf) (1)					
North America	**$ 1.09**	$ 1.23	$ 1.09	**$ 1.19**	$ 1.27
International average	**$ 7.81**	$ 6.24	$ 8.76	**$ 6.51**	$ 7.26
North Sea	**$ 9.38**	$ 9.61	$ 9.52	**$ 8.95**	$ 9.85
Offshore Africa	**$ 6.94**	$ 5.75	$ 8.65	**$ 5.98**	$ 6.83
Natural gas average	**$ 1.12**	$ 1.26	$ 1.13	**$ 1.22**	$ 1.30
Average ($/BOE) (1)	**$ 10.53**	$ 11.81	$ 11.75	**$ 11.73**	$ 12.74

(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 year ended December 31, 2024 averaged $12.55 per bbl, a decrease of 13% from $14.46 per bbl for the year ended December 31, 2023. North America crude oil and NGLs production expense for the fourth quarter of 2024 of $10.83 per bbl decreased 14% from $12.56 per bbl for the fourth quarter of 2023 and decreased 12% from $12.36 per bbl for the third quarter of 2024. The decrease in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected lower energy costs. The decrease in crude oil and NGLs production expense per bbl for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected lower maintenance activities in the fourth quarter of 2024, combined with higher production volumes.

North America natural gas production expense for the year ended December 31, 2024 averaged $1.19 per Mcf, a decrease of 6% from $1.27 per Mcf for the year ended December 31, 2023. North America natural gas production expense for the fourth quarter of 2024 of $1.09 per Mcf was comparable with $1.09 per Mcf for the fourth quarter of 2023 and decreased 11% from $1.23 per Mcf for the third quarter of 2024. The decrease in natural gas production expense per Mcf for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected lower energy costs and maintenance activities. The decrease in natural gas production expense per Mcf for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected higher production volumes in the fourth quarter of 2024 as a result of strong drilling results and the acquisition of Chevron's assets in December 2024.

International

International crude oil and NGLs production expense for the year ended December 31, 2024 averaged $62.99 per bbl, an increase of 31% from $48.16 per bbl for the year ended December 31, 2023. International crude oil and NGLs production expense for the fourth quarter of 2024 of $77.66 per bbl increased 41% from $54.95 per bbl for the fourth quarter of 2023 and increased 49% from $52.04 per bbl for the third quarter of 2024. The increase in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2024 from the comparable periods 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 Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
North America	**$ 1,010**	$ 924	$ 971	**$ 3,831**	$ 3,679
North Sea	**221**	17	466	**279**	494
Offshore Africa	**46**	96	66	**297**	213
Depletion, depreciation and amortization	**$ 1,277**	$ 1,037	$ 1,503	**$ 4,407**	$ 4,386
Less: Recoverability charge (1) (2)	**160**	—	436	**222**	436
Adjusted depletion, depreciation and amortization (3)	**$ 1,117**	$ 1,037	$ 1,067	**$ 4,185**	$ 3,950
$/BOE (4)	**$ 13.01**	$ 13.27	$ 12.46	**$ 12.92**	$ 12.27

(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 (December 31, 2023 – $436 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) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

(3) 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.

(4) 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 year ended December 31, 2024 averaged $12.92 per BOE, an increase of 5% from $12.27 per BOE for the year ended December 31, 2023. Adjusted depletion, depreciation and amortization expense for the fourth quarter of 2024 averaged $13.01 per BOE, an increase of 4% from $12.46 per BOE for the fourth quarter of 2023 and comparable with $13.27 per BOE for the third quarter of 2024. The increase in adjusted depletion, depreciation and amortization expense per BOE for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected the impact of changes in North America depletion rates due to changes in reserve estimates at December 31, 2023.

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 Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
North America	**$ 58**	$ 58	$ 58	**$ 231**	$ 234
North Sea	**17**	16	12	**65**	46
Offshore Africa	**3**	2	2	**9**	8
Asset retirement obligation accretion	**$ 78**	$ 76	$ 72	**$ 305**	$ 288
$/BOE (1)	**$ 0.89**	$ 0.97	$ 0.84	**$ 0.94**	$ 0.89

(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 year ended December 31, 2024 averaged $0.94 per BOE, an increase of 6% from $0.89 per BOE for the year ended December 31, 2023. Asset retirement obligation accretion expense for the fourth quarter of 2024 averaged $0.89 per BOE, an increase of 6% from $0.84 per BOE for the fourth quarter of 2023 and a decrease of 8% from $0.97 per BOE for the third quarter of 2024. The increase in asset retirement obligation accretion expense per BOE for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected the impact of the Company's estimate for future abandonment costs for the Ninian field in the North Sea at December 31, 2023. The decrease in asset retirement obligation accretion expense per BOE for the fourth quarter of 2024 from the third quarter of 2024 reflected higher sales volumes.

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, resulting in record SCO production averaging 534,631 bbl/d in the fourth quarter of 2024. The acquisition of an additional 20% working interest in AOSP also contributed to increased volumes in the fourth quarter of 2024.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Realized SCO sales price (1)	**$ 95.08**	$ 100.93	$ 98.73	**$ 98.03**	$ 100.06
Bitumen value for royalty purposes (2)	**$ 69.35**	$ 76.16	$ 61.73	**$ 72.68**	$ 65.43
Bitumen royalties (3)	**$ 17.20**	$ 17.71	$ 11.57	**$ 17.23**	$ 14.43
Transportation (1)	**$ 3.60**	$ 3.34	$ 1.85	**$ 2.91**	$ 1.89

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

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

(3) Calculated as royalties divided by sales volumes.

The realized SCO sales price averaged $98.03 per bbl for the year ended December 31, 2024, comparable with $100.06 per bbl for the year ended December 31, 2023. The realized SCO sales price averaged $95.08 per bbl for the fourth quarter of 2024, a decrease of 4% from $98.73 per bbl for the fourth quarter of 2023 and a decrease of 6% from $100.93 per bbl for the third quarter of 2024. The decrease in realized SCO sales price per bbl for the fourth quarter of 2024 from the comparable periods primarily reflected 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 three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected an increase in average bitumen pricing for royalty purposes in 2024.

Transportation expense averaged $2.91 per bbl for the year ended December 31, 2024, an increase of 54% from $1.89 per bbl for the year ended December 31, 2023. Transportation expense averaged $3.60 per bbl for the fourth quarter of 2024, an increase of 95% from $1.85 per bbl for the fourth quarter of 2023 and an increase of 8% from $3.34 per bbl for the third quarter of 2024. The increase in transportation expense per bbl for the three months and year ended December 31, 2024 from the comparable periods primarily reflected higher volumes shipped on the TMX pipeline.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Production expense, excluding natural gas costs	**$ 991**	$ 917	$ 904	**$ 3,801**	$ 3,794
Natural gas costs	**28**	18	43	**120**	195
Production expense	**$ 1,019**	$ 935	$ 947	**$ 3,921**	$ 3,989

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Production expense, excluding natural gas costs (1)	**$ 20.39**	$ 20.27	$ 20.00	**$ 22.18**	$ 23.13
Natural gas costs (2)	**0.58**	0.40	0.96	**0.70**	1.19
Production expense (3)	**$ 20.97**	$ 20.67	$ 20.96	**$ 22.88**	$ 24.32
Sales volumes (bbl/d)	**528,248**	491,635	491,339	**468,280**	449,282

(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 $1,019 million for the fourth quarter of 2024, an increase of 8% from $947 million for the fourth quarter of 2023 and an increase of 9% from $935 million for the third quarter of 2024 primarily reflecting the acquisition of Chevron's assets in December 2024. The Company continues to focus on cost control and driving efficiencies across the Oil Sands Mining and Upgrading segment.

Production expense for the year ended December 31, 2024 averaged $22.88 per bbl, a decrease of 6% from $24.32 per bbl for the year ended December 31, 2023. Production expense for the fourth quarter of 2024 averaged $20.97 per bbl, comparable with $20.96 per bbl for the fourth quarter of 2023 and $20.67 per bbl for the third quarter of 2024. The decrease in production expense per bbl for the year ended December 31, 2024 from the year ended December 31, 2023 reflected higher production volumes from strong utilization, combined with lower energy costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Depletion, depreciation and amortization	**$ 621**	$ 556	$ 554	**$ 2,258**	$ 2,011
$/bbl [1]	**$ 12.76**	$ 12.27	$ 12.25	**$ 13.17**	$ 12.26

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

Depletion, depreciation and amortization expense for the year ended December 31, 2024 averaged $13.17 per bbl, an increase of 7% from $12.26 per bbl for the year ended December 31, 2023. Depletion, depreciation and amortization expense for the fourth quarter of 2024 of $12.76 per bbl increased 4% from $12.25 per bbl for the fourth quarter of 2023 and increased 4% from $12.27 per bbl for the third quarter of 2024. The increase in depletion, depreciation and amortization expense per bbl for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected derecognitions related to the Horizon turnaround in the second quarter of 2024, partially offset by higher sales volumes in 2024. The increase in depletion, depreciation, and amortization expense per bbl for the fourth quarter of 2024 from the comparable periods also reflected a higher depletable base due to assets additions, including the acquisition of Chevron's assets in December 2024, partially offset by higher sales volumes in the fourth quarter of 2024.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Asset retirement obligation accretion	**$ 20**	$ 21	$ 19	**$ 84**	$ 78
$/bbl [1]	**$ 0.44**	$ 0.46	$ 0.43	**$ 0.49**	$ 0.48

(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 year ended December 31, 2024 of $0.49 per bbl was comparable with $0.48 per bbl for the year ended December 31, 2023. Asset retirement obligation accretion expense for the fourth quarter of 2024 of $0.44 per bbl was comparable with $0.43 per bbl for the fourth quarter of 2023 and decreased 4% from $0.46 per bbl for the third quarter of 2024. The decrease in asset retirement obligation accretion expense per bbl for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected the impact of higher sales volumes in the fourth quarter of 2024.

MIDSTREAM AND REFINING

($ millions)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Product sales					
Midstream activities	**$ 21**	$ 20	$ 20	**$ 82**	$ 76
NWRP, refined product sales and other	**193**	191	236	**813**	926
Segmented revenue	**214**	211	256	**895**	1,002
Less:					
NWRP, refining toll	**65**	75	82	**295**	303
Midstream activities	**5**	3	7	**20**	29
Production expense	**70**	78	89	**315**	332
NWRP, transportation and feedstock costs	**164**	169	166	**685**	664
Depreciation	**3**	5	4	**16**	16
Segmented loss	**$ (23)**	$ (41)	$ (3)	**$ (121)**	$ (10)

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 50,000 bbl/d bitumen upgrader and refinery that processes approximately 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 fourth quarter of 2024, production of ultra-low sulphur diesel and other refined products averaged 77,742 BOE/d (19,436 BOE/d to the Company) (three months ended September 30, 2024 – 72,109 BOE/d; 18,027 BOE/d to the Company; three months ended December 31, 2023 – 83,294 BOE/d; 20,824 BOE/d to the Company), reflecting the 25% toll payer commitment.

During the third quarter of 2024, NWRP repaid $500 million of 3.20% series A bonds.

During the second quarter of 2024, NWRP issued $700 million of 4.85% series P bonds due June 2034 and $600 million of 5.08% series Q bonds due June 2054.

During the second quarter of 2024, NWRP amended its syndicated credit facility to extend the revolving facility originally maturing June 2025 to June 2027, reduce the availability on the revolving facility from $2,175 million to $1,900 million, and reduce the availability of the non-revolving facility from $940 million to $500 million. Additionally, in the third and fourth quarter of 2024, NWRP repaid an additional $150 million and $100 million, respectively, on the non-revolving facility, reducing the availability to $250 million.

As at December 31, 2024, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $509 million (December 31, 2023 – $555 million). For the three months ended December 31, 2024, the Company's recovery of its share of unrecognized equity losses was $1 million (year ended December 31, 2024 – recovery of unrecognized equity losses of $46 million; three months ended December 31, 2023 – unrecognized equity loss of $5 million; year ended December 31, 2023 – unrecognized equity loss of $4 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Administration expense	**$ 127**	$ 126	$ 119	**$ 503**	$ 452
$/BOE (1)	**$ 0.95**	$ 1.02	$ 0.91	**$ 1.02**	$ 0.93
Sales volumes (BOE/d) (2)	**1,460,909**	1,342,508	1,422,198	**1,353,166**	1,331,092

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

Administration expense for the year ended December 31, 2024 of $1.02 per BOE increased 10% from $0.93 per BOE for the year ended December 31, 2023. Administration expense for the fourth quarter of 2024 of $0.95 per BOE increased 4% from $0.91 per BOE for the fourth quarter of 2023 and decreased 7% from $1.02 per BOE for the third quarter of 2024. The increase in administration expense per BOE for the three months and year ended December 31, 2024 from the comparable periods in 2023 primarily reflected higher personnel costs, partially offset by higher overhead recoveries. The decrease in administration expense per BOE for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected higher sales volumes.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Share-based compensation expense (recovery)	**$ 44**	$ (46)	$ 57	**$ 279**	$ 491

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, and by individual employee performance and the extent to which certain other performance measures are met.

The Company recognized $279 million of share-based compensation expense for the year ended December 31, 2024, 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 Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Interest and other financing expense	**$ 142**	$ 154	$ 117	**$ 592**	$ 636
Less: Interest (income) and other expense [(1)]	**(47)**	(5)	(53)	**(81)**	(55)
Interest expense on long-term debt and lease liabilities [(1)]	**$ 189**	$ 159	$ 170	**$ 673**	$ 691
Average current and long-term debt [(2)]	**$ 13,285**	$ 11,130	$ 12,350	**$ 11,895**	$ 12,749
Average lease liabilities [(2)]	**1,457**	1,511	1,484	**1,509**	1,500
Average long-term debt and lease liabilities [(2)]	**$ 14,742**	$ 12,641	$ 13,834	**$ 13,404**	$ 14,249
Average effective interest rate [(3)] [(4)]	**5.0%**	4.9%	4.8%	**4.9%**	4.8%
Interest and other financing expense ($/BOE) [(5)]	**$ 1.06**	$ 1.24	$ 0.90	**$ 1.20**	$ 1.31
Sales volumes (BOE/d) [(6)]	**1,460,909**	1,342,508	1,422,198	**1,353,166**	1,331,092

(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 year ended December 31, 2024 decreased 8% to $1.20 per BOE from $1.31 per BOE for the year ended December 31, 2023. Interest and other financing expense for the fourth quarter of 2024 increased 18% to $1.06 per BOE from $0.90 per BOE for the fourth quarter of 2023 and decreased 15% from $1.24 per BOE for the third quarter of 2024. The decrease in interest and other financing expense per BOE for the year ended December 31, 2024 from the year ended December 31, 2023 primarily reflected lower average debt levels. The increase in interest and other financing expense per BOE for the fourth quarter of 2024 from the fourth quarter of 2023 primarily reflected higher average debt levels as a result of debt issuances in the fourth quarter of 2024. The decrease in interest and other financing expense per BOE for the fourth quarter of 2024 from the third quarter of 2024 primarily reflected higher sales volumes in the fourth quarter of 2024, partially offset by higher average debt levels.

The Company's average effective interest rate for the three months and year ended December 31, 2024 averaged 5.0% and 4.9%, respectively, an increase from the comparable periods, reflecting higher prevailing interest rates on long-term debt held during 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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Foreign currency contracts	**$ 144**	$ (27)	$ (15)	**$ 155**	$ (17)
Natural gas financial instruments (1) (2) (3)	**2**	6	(2)	**13**	3
Net realized loss (gain)	**146**	(21)	(17)	**168**	(14)
Foreign currency contracts	**(2)**	5	(16)	**15**	(9)
Natural gas financial instruments (1) (2) (3)	**(2)**	(5)	9	**(6)**	21
Net unrealized (gain) loss	**(4)**	—	(7)	**9**	12
Net loss (gain)	**$ 142**	$ (21)	$ (24)	**$ 177**	$ (2)

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

(2) 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.

(3) 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 year ended December 31, 2024, net realized risk management losses were related to the settlement of foreign currency contracts and natural gas financial instruments. The Company recorded a net unrealized loss of $9 million ($10 million after tax of $1 million) on its risk management activities for the year ended December 31, 2024, and a net unrealized gain of $4 million ($3 million after-tax of $1 million) for the fourth quarter of 2024 (three months ended September 30, 2024 – $nil; three months ended December 31, 2023 – unrealized gain of $7 million ($9 million after tax of $2 million); year ended December 31, 2023 – unrealized loss of $12 million ($7 million after tax of $5 million)).

Further details related to outstanding derivative financial instruments as at December 31, 2024 are disclosed in note 16 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Net realized (gain) loss	**$ (62)**	$ 30	$ 11	**$ 67**	$ (19)
Net unrealized loss (gain)	**782**	(148)	(276)	**888**	(260)
Net loss (gain) (1)	**$ 720**	$ (118)	$ (265)	**$ 955**	$ (279)

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

The net realized foreign exchange loss for the year ended December 31, 2024 was primarily related to the repayment of US dollar debt, partially offset by foreign exchange rate fluctuations on the settlement of working capital items denominated in US dollars. The net unrealized foreign exchange loss for the year ended December 31, 2024 was primarily related to the translation of outstanding US dollar debt, partially offset by the repayment of the US dollar debt during the second quarter of 2024. The US/Canadian dollar exchange rate as at December 31, 2024 was US$0.6942 (September 30, 2024 – US$0.7405, December 31, 2023 – US$0.7573).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
North America [1]	**$ 261**	$ 433	$ 487	**$ 1,654**	$ 1,853
North Sea	**(11)**	(12)	3	**(41)**	(6)
Offshore Africa	**35**	12	20	**57**	73
Current PRT – North Sea	**(67)**	(47)	(13)	**(134)**	(58)
Other taxes	**3**	3	8	**(5)**	17
Current income tax	**221**	389	505	**1,531**	1,879
Deferred corporate income tax	**372**	120	64	**520**	267
Deferred PRT – North Sea	**(145)**	34	(238)	**(98)**	(214)
Deferred income tax	**227**	154	(174)	**422**	53
Income tax	**$ 448**	$ 543	$ 331	**$ 1,953**	$ 1,932
Earnings before taxes	**$ 1,586**	$ 2,809	$ 2,958	**$ 8,059**	$ 10,165
Effective tax rate on net earnings [2]	**28%**	19%	11%	**24%**	19%

($ millions, except effective tax rates)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Income tax	**$ 448**	$ 543	$ 331	**$ 1,953**	$ 1,932
Tax effect on non-operating items [3]	**143**	1	331	**175**	345
Current PRT – North Sea	**67**	47	13	**134**	58
Deferred PRT – North Sea	**56**	(34)	33	**9**	9
Other taxes	**(3)**	(3)	(8)	**5**	(17)
Effective tax on adjusted net earnings	**$ 711**	$ 554	$ 700	**$ 2,276**	$ 2,327
Adjusted net earnings from operations [4]	**$ 1,977**	$ 2,071	$ 2,546	**$ 7,414**	$ 8,533
Adjusted net earnings from operations, before taxes	**$ 2,688**	$ 2,625	$ 3,246	**$ 9,690**	$ 10,860
Effective tax rate on adjusted net earnings from operations [5] [6]	**26%**	21%	22%	**23%**	21%

(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 recoverability charges related to the increase in future abandonment costs for Ninian field in the North Sea, and the notice to withdraw from Block 11B/12B in South Africa.

(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 three months and year ended December 31, 2024 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 three months and year ended December 31, 2024 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[(1) (2)]

($ millions)	Three Months Ended Dec 31 2024	Sep 30 2024	Dec 31 2023	Year Ended Dec 31 2024	Dec 31 2023
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 9**	$ 8	$ 12	**$ 82**	$ 47
Net property acquisitions (dispositions) (3)	**330**	—	—	**330**	(3)
Total Exploration and Evaluation Assets	**339**	8	12	**412**	44
Property, Plant and Equipment					
Net property acquisitions (dispositions) (3)	**2,553**	88	(1)	**2,642**	24
Well drilling, completion and equipping	**472**	469	274	**1,832**	1,579
Production and related facilities	**341**	387	251	**1,336**	1,267
Other	**14**	14	13	**53**	61
Total Property, Plant and Equipment	**3,380**	958	537	**5,863**	2,931
Total Exploration and Production	**3,719**	966	549	**6,275**	2,975
Oil Sands Mining and Upgrading					
Project costs	**66**	55	78	**306**	348
Sustaining capital	**357**	302	320	**1,466**	1,347
Turnaround costs	**16**	12	17	**153**	189
Net property acquisitions (dispositions) (3)	**6,175**	—	(1)	**6,173**	5
Other	**1**	3	1	**6**	5
Total Oil Sands Mining and Upgrading	**6,615**	372	415	**8,104**	1,894
Midstream and Refining	**1**	3	4	**11**	10
Head Office	**13**	8	7	**41**	30
Net capital expenditures	**$ 10,348**	$ 1,349	$ 975	**$ 14,431**	$ 4,909
Abandonment expenditures	**$ 151**	$ 204	$ 149	**$ 646**	$ 509
By Segment					
North America	**$ 3,632**	$ 896	$ 479	**$ 6,033**	$ 2,770
North Sea	**3**	29	11	**39**	33
Offshore Africa	**84**	41	59	**203**	172
Oil Sands Mining and Upgrading	**6,615**	372	415	**8,104**	1,894
Midstream and Refining	**1**	3	4	**11**	10
Head Office	**13**	8	7	**41**	30
Net capital expenditures	**$ 10,348**	$ 1,349	$ 975	**$ 14,431**	$ 4,909

(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 and 2023 and has been updated for all periods presented. 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 $14,431 million for the year ended December 31, 2024 compared with $4,909 million for the year ended December 31, 2023. Net capital expenditures were $10,348 million for the fourth quarter of 2024 compared with $975 million for the fourth quarter of 2023 and $1,349 million for the third quarter of 2024.

In addition, the Company reported abandonment expenditures of $646 million for the year ended December 31, 2024 compared with $509 million for the year ended December 31, 2023. Abandonment expenditures were $151 million for the fourth quarter of 2024 compared with $149 million for the fourth quarter of 2023 and $204 million for the third quarter of 2024.

Acquisition of Chevron's Assets

In December 2024, the Company completed the acquisition of Chevron's assets for total cash consideration of $9,163 million, subject to final closing adjustments. The acquisition includes a 70% operated working interest in the light crude oil and liquids-rich Duvernay asset play in Alberta and a 20% working interest in AOSP. As a result of the acquisition, the Company now has a 90% direct and indirect working interest in AOSP, which includes the Muskeg River and Jackpine mines, the Scotford Upgrader, and the Quest Carbon Capture and Storage facility ("Quest"). The acquisition also includes various working interests in a number of other non-producing oil sands leases. The Company consolidates its interests in the assets, liabilities, revenue, and expenses of both the AOSP and Duvernay joint operations. Further details are disclosed in note 5 to the financial statements.

Drilling Activity[1] [2]

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Net successful crude oil wells [3]	**100**	83	42	**307**	221
Net successful natural gas wells	**14**	24	9	**78**	61
Dry wells	**—**	1	—	**2**	2
Total	**114**	108	51	**387**	284
Success rate	**100%**	99%	100%	**99%**	99%

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

(2) Excludes stratigraphic and service wells.

(3) Includes bitumen wells.

North America

During the fourth quarter of 2024, the Company drilled 14 net natural gas wells, 73 net primary heavy crude oil wells, 16 net bitumen (thermal oil) wells and 11 net light crude oil wells.

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023
Adjusted working capital [1]	**$ 174**	$ 365	$ 712
Long-term debt, net [2]	**$ 18,688**	$ 9,308	$ 9,922
Shareholders' equity	**$ 39,468**	$ 39,897	$ 39,832
Debt to book capitalization [2]	**32.1%**	18.9%	19.9%
After-tax return on average capital employed [3]	**12.7%**	15.9%	17.2%

(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 December 31, 2024, 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, 2023. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions. The Company continues to believe its internally generated cash flows from operating activities, supported by its ongoing hedge policy, the flexibility of its capital expenditure programs and multi-year financial plans, its existing bank credit facilities, and its ability to raise new debt on commercially acceptable terms will provide sufficient liquidity to sustain its operations in the short-, medium-, and long-term and support its growth strategy.

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

- Monitoring cash flows from operating activities, which is the primary source of funds;
- Monitoring exposure to individual customers, contractors, suppliers, and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of 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 fourth quarter of 2024, the Company extended its $2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028, and its $500 million revolving credit facility from February 2025 to February 2026.
  - During the fourth quarter of 2024 and in connection with the acquisition of Chevron's assets, the Company entered into a $4,000 million non-revolving term credit facility maturing December 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.
  - During the fourth quarter of 2024, the Company issued, by private placement, $500 million of 4.15% medium-term notes due December 2031.
  - During the second quarter of 2024, the Company repaid $320 million of 3.55% 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. During 2024, no medium-term notes were issued in Canada under the base shelf prospectus.
  - During the fourth quarter of 2024, the Company issued, by private placement, US$750 million of 5.00% notes due December 2029 and US$750 million of 5.40% notes due December 2034.
  - Subsequent to December 31, 2024, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.
  - During the second quarter of 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.
  - 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. During 2024, no US dollar debt securities were issued in the United States under the base shelf prospectus.

As at December 31, 2024, the Company had undrawn revolving bank credit facilities of $4,562 million. Additionally, the Company had in place a fully drawn term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $4,693 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit. As at December 31, 2024, the Company had $672 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 $18,688 million as at December 31, 2024 (December 31, 2023 – $9,922 million), resulting in a debt to book capitalization ratio of 32.1% (December 31, 2023 – 19.9%); 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 December 31, 2024, 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 December 31, 2024 are discussed in note 9 to the financial statements.

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.

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of put options is in addition to the above parameters.

As at December 31, 2024, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt (1)	$ 2,400	$ 941	$ 7,494	$ 8,074
Other long-term liabilities (2)	$ 263	$ 187	$ 405	$ 617
Interest and other financing expense (3)	$ 1,024	$ 951	$ 1,978	$ 3,574

(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, $187 million; two to less than five years, $405 million; and thereafter, $617 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 December 31, 2024.

Share Capital(1)

As at December 31, 2024, there were 2,102,996,000 common shares outstanding (December 31, 2023 – 2,144,815,000 common shares) and 50,806,000 stock options outstanding (December 31, 2023 – 52,410,000 stock options). As at March 4, 2025, the Company had 2,100,007,000 common shares outstanding and 57,117,000 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 payable 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, beginning with the dividend paid on January 3, 2025. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525 per common share.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45 per common share.

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

On March 8, 2024, 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 180,462,858 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the year ended December 31, 2024, the Company purchased 55,350,000 common shares at a weighted average price of $48.07 per common share for a total cost, including tax, of $2,700 million. Retained earnings were reduced by $2,414 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2024, up to and including March 4, 2025, the Company purchased 7,740,000 common shares at a weighted average price of $44.11 per common share for a total cost, including tax, of $344 million.

On March 5, 2025, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

(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.

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 December 31, 2024:

($ millions)		2025		2026		2027		2028		2029		Thereafter
Product transportation, purchases, and processing (1) (2) (3)	$	2,249	$	2,245	$	2,097	$	1,983	$	1,882	$	19,310
North West Redwater Partnership service toll (4)	$	141	$	121	$	103	$	104	$	104	$	4,203
Offshore vessels and equipment	$	88	$	—	$	—	$	—	$	—	$	—
Field equipment and power	$	43	$	29	$	29	$	28	$	27	$	216
Other	$	124	$	111	$	21	$	22	$	21	$	247

(1) The Company's commitment for the 20-year product transportation agreement 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) During the third quarter of 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(3) The acquisition of Chevron's assets in the fourth quarter of 2024 included approximately $1,292 million of product transportation and processing commitments and approximately $75 million of field equipment and power commitments.

(4) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,161 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.

SUBSEQUENT EVENTS

On January 29, 2025, the Company announced that pursuant to an agreement with Shell Canada Limited and affiliates ("Shell") and as a result of certain conditions being met, the Company will acquire a 10% working interest in the AOSP mines, associated reserves and additional working interests in a number of other non-producing oil sands leases in exchange for a 10% working interest in the Scotford Upgrader and Quest. Following the close of the transaction, the Company will have a 100% direct working interest in the AOSP mines and an 80% interest in the Scotford Upgrader and Quest, where Shell will remain operator. The transaction does not include an exchange of cash, except for regular closing adjustments for working capital. The acquisition is targeted to close in the first half of 2025, subject to obtaining the necessary regulatory approvals.

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, 2023.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2024 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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Net earnings	**$ 1,138**	$ 2,266	$ 2,627	**$ 6,106**	$ 8,233
Share-based compensation, net of tax [(1)]	**39**	(48)	51	**257**	474
Unrealized risk management (gain) loss, net of tax [(2)]	**(3)**	1	(9)	**10**	7
Unrealized foreign exchange loss (gain), net of tax [(3)]	**782**	(148)	(276)	**888**	(260)
Realized foreign exchange loss on repayment of US dollar debt securities, net of tax [(4)]	**—**	—	—	**135**	—
Loss (gain) from investments, net of tax [(5)]	**—**	—	40	**(50)**	(34)
Recoverability charge, net of tax [(6) (7)]	**21**	—	113	**68**	113
Non-operating items, net of tax	**839**	(195)	(81)	**1,308**	300
Adjusted net earnings from operations	**$ 1,977**	$ 2,071	$ 2,546	**$ 7,414**	$ 8,533

(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 December 31, 2024 was an expense of $44 million (three months ended September 30, 2024 – $46 million recovery, three months ended December 31, 2023 – $57 million expense; year ended December 31, 2024 – $279 million expense; year ended December 31, 2023 – $491 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 gain for the three months ended December 31, 2024 was $4 million (three months ended September 30, 2024 – $nil, three months ended December 31, 2023 – $7 million gain; year ended December 31, 2024 – $9 million loss; year ended December 31, 2023 – $12 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) During the second quarter of 2024, the Company repaid US$500 million of 3.80% debt securities due April 2024, resulting in a pre- and after-tax foreign exchange loss of $135 million.

(5) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with gains and losses recognized in net earnings. 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. There is a $nil net tax impact on the sale as the Company has sufficient capital losses to offset the capital gain on the sale.

(6) The Company recognized a pre-tax recoverability charge of $160 million ($21 million after tax) (December 31, 2023 - $436 million, $113 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.

(7) In connection with the Company’s notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million ($47 million after-tax) of exploration and evaluation assets through depletion, depreciation and amortization expense.

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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Cash flows from operating activities	**$ 3,432**	$ 3,002	$ 4,815	**$ 13,386**	$ 12,353
Net change in non-cash working capital	**563**	680	(562)	**743**	2,417
Abandonment expenditures	**151**	204	149	**646**	509
Movements in other long-term assets (1)	**40**	35	17	**84**	(5)
Adjusted funds flow	**$ 4,186**	$ 3,921	$ 4,419	**$ 14,859**	$ 15,274

(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 15 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 non-GAAP financial measures: realized price and transportation, reconciled below to their respective line item in note 18 to the financial statements.

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

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

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

	Three Months Ended			Year Ended	
($ millions, except bbl/d and $/bbl)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs (bbl/d)					
North America	**533,126**	479,889	526,350	**504,339**	497,604
International					
North Sea	**10,686**	9,020	15,032	**11,455**	10,749
Offshore Africa	**8,423**	20,450	17,705	**11,198**	14,882
Total International	**19,109**	29,470	32,737	**22,653**	25,631
Total sales volumes	**552,235**	509,359	559,087	**526,992**	523,235
Crude oil and NGLs sales (1)	**$ 4,999**	$ 4,653	$ 4,790	**$ 19,641**	$ 18,387
Less: Blending and feedstock costs (2)	**1,177**	946	1,222	**4,643**	4,568
Realized crude oil and NGLs sales	**$ 3,822**	$ 3,707	$ 3,568	**$ 14,998**	$ 13,819
Realized price ($/bbl)	**$ 75.22**	$ 79.15	$ 69.39	**$ 77.76**	$ 72.36

(1) Crude oil and NGLs sales in note 18 to the financial statements.

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

	Three Months Ended			Year Ended	
($ millions, except BOE/d and $/BOE)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Barrels of oil equivalent (BOE/d)					
North America	**911,869**	819,606	895,996	**860,367**	854,138
International					
North Sea	**11,285**	9,246	15,296	**11,791**	11,034
Offshore Africa	**9,507**	22,021	19,567	**12,728**	16,638
Total International	**20,792**	31,267	34,863	**24,519**	27,672
Total sales volumes	**932,661**	850,873	930,859	**884,886**	881,810
Barrels of oil equivalent sales (1)	**$ 5,424**	$ 4,889	$ 5,365	**$ 21,105**	$ 20,820
Less: Blending and feedstock costs (2)	**1,177**	946	1,222	**4,643**	4,568
Less: Sulphur (income) expense	**(3)**	2	(2)	**3**	(14)
Realized barrels of oil equivalent sales	**$ 4,250**	$ 3,941	$ 4,145	**$ 16,459**	$ 16,266
Realized price ($/BOE)	**$ 49.54**	$ 50.36	$ 48.41	**$ 50.82**	$ 50.54

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 18 to the financial statements.

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

Transportation – Exploration and Production

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

	Three Months Ended			Year Ended	
($ millions, except $ per unit amounts)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Transportation, blending and feedstock [1]	**$ 1,611**	$ 1,312	$ 1,531	**$ 6,195**	$ 5,816
Less: Blending and feedstock costs	**1,177**	946	1,222	**4,643**	4,568
Transportation	**$ 434**	$ 366	$ 309	**$ 1,552**	$ 1,248
Transportation ($/BOE)	**$ 5.06**	$ 4.67	$ 3.61	**$ 4.78**	$ 3.88
Amounts attributed to crude oil and NGLs	**$ 309**	$ 246	$ 197	**$ 1,061**	$ 807
Transportation ($/bbl)	**$ 6.08**	$ 5.26	$ 3.83	**$ 5.50**	$ 4.23
Amounts attributed to natural gas	**$ 125**	$ 120	$ 112	**$ 491**	$ 441
Transportation ($/Mcf)	**$ 0.59**	$ 0.63	$ 0.54	**$ 0.62**	$ 0.56

(1) Transportation, blending and feedstock in note 18 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 exclude the impact of blending costs. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

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

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

	Three Months Ended			Year Ended	
($ millions, except $/bbl and royalty rates)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Crude oil and NGLs sales [1]	**$ 4,830**	$ 4,357	$ 4,451	**$ 18,740**	$ 17,375
Less: Blending and feedstock costs [2]	**1,177**	946	1,222	**4,643**	4,568
Realized crude oil and NGLs sales	**$ 3,653**	$ 3,411	$ 3,229	**$ 14,097**	$ 12,807
Realized crude oil and NGLs prices ($/bbl)	**$ 74.46**	$ 77.29	$ 66.69	**$ 76.37**	$ 70.51
Crude oil and NGLs royalties [3]	**$ 747**	$ 694	$ 567	**$ 2,842**	$ 2,340
Crude oil and NGLs royalty rates	**20%**	20%	18%	**20%**	18%

(1) Crude oil and NGLs sales in note 18 to the financial statements.

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

(3) Item is a component of royalties in note 18 to the financial statements.

Realized Product Prices and Transportation – Oil Sands Mining and Upgrading

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

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

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

	Three Months Ended			Year Ended	
($ millions, except for bbl/d and $/bbl)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
SCO sales volumes (bbl/d)	**528,248**	491,635	491,339	**468,280**	449,282
Crude oil and NGLs sales [(1)]	**$ 5,362**	$ 5,208	$ 5,042	**$ 19,263**	$ 18,661
Less: Blending and feedstock costs	**741**	643	579	**2,462**	2,253
Realized SCO sales	**$ 4,621**	$ 4,565	$ 4,463	**$ 16,801**	$ 16,408
Realized SCO sales price ($/bbl)	**$ 95.08**	$ 100.93	$ 98.73	**$ 98.03**	$ 100.06
Transportation, blending and feedstock [(2)]	**$ 915**	$ 794	$ 663	**$ 2,959**	$ 2,563
Less: Blending and feedstock costs	**741**	643	579	**2,462**	2,253
Transportation	**$ 174**	$ 151	$ 84	**$ 497**	$ 310
Transportation ($/bbl)	**$ 3.60**	$ 3.34	$ 1.85	**$ 2.91**	$ 1.89

(1) Crude oil and NGLs sales in note 18 to the financial statements.

(2) Transportation, blending and feedstock in note 18 to the financial statements.

Change in Composition of Non-GAAP Financial Measure

During the fourth quarter of 2023, the Company revised the composition of its Net Capital Expenditures non-GAAP financial measure to exclude expenditures related to the Company's abandonment program. The revision was made during Management's assessment of its annual capital budgeting process and will provide users a better representation of the Company's performance and the composition of its capital budget. The composition of this measure has been updated for all periods presented.

Additionally, 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 or 2023.

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.

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Cash flows used in investing activities	**$ 10,414**	$ 1,274	$ 946	**$ 14,095**	$ 4,858
Net proceeds from investments	**—**	—	—	**575**	—
Working capital acquired from Chevron	**(115)**	—	—	**(115)**	—
Net change in non-cash working capital	**49**	75	29	**(124)**	51
Net capital expenditures	**10,348**	1,349	975	**14,431**	4,909
Abandonment expenditures	**151**	204	149	**646**	509
Capital and abandonment expenditures	**$ 10,499**	$ 1,553	$ 1,124	**$ 15,077**	$ 5,418

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)	**Dec 31 2024**	Sep 30 2024	Dec 31 2023
Undrawn bank credit facilities	**$ 4,562**	$ 5,450	$ 5,450
Cash and cash equivalents	**131**	721	877
Investments (1)	**—**	—	525
Liquidity	**$ 4,693**	$ 6,171	$ 6,852

(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 14 to the financial statements. A reconciliation of long-term debt, net is presented below.

($ millions)	Dec 31 2024	Sep 30 2024	Dec 31 2023
Long-term debt	**$ 18,819**	$ 10,029	$ 10,799
Less: cash and cash equivalents	**131**	721	877
Long-term debt, net	**$ 18,688**	$ 9,308	$ 9,922

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 14 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)	Dec 31 2024	Sep 30 2024	Dec 31 2023
Interest adjusted after-tax return:			
Net earnings, 12 months trailing	**$ 6,106**	$ 7,595	$ 8,233
Interest and other financing expense, net of tax, 12 months trailing (1)	**454**	435	490
Interest adjusted after-tax return	**$ 6,560**	$ 8,030	$ 8,723
12 months average current portion long-term debt (2)	**$ 1,525**	$ 1,366	$ 1,259
12 months average long-term debt (2)	**10,642**	9,366	10,354
12 months average common shareholders' equity (2)	**39,635**	39,668	38,974
12 months average capital employed	**$ 51,802**	$ 50,400	$ 50,587
After-tax return on average capital employed	**12.7%**	15.9%	17.2%

(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	**Dec 31 2024**	Dec 31 2023
ASSETS			
Current assets			
Cash and cash equivalents		**$ 131**	$ 877
Accounts receivable		**4,126**	3,189
Inventory		**2,793**	2,034
Prepaids and other		**279**	471
Investments	7	**—**	525
Current portion of other long-term assets	8	**76**	71
		7,405	7,167
Exploration and evaluation assets	4	**2,526**	2,208
Property, plant and equipment	5	**73,414**	64,581
Lease assets	6	**1,394**	1,458
Other long-term assets	8	**620**	541
		$ 85,359	$ 75,955
LIABILITIES			
Current liabilities			
Accounts payable		**$ 1,079**	$ 1,418
Accrued liabilities		**4,525**	3,534
Current income taxes payable		**92**	—
Current portion of long-term debt	9	**2,400**	980
Current portion of other long-term liabilities	10	**1,535**	1,503
		9,631	7,435
Long-term debt	9	**16,419**	9,819
Other long-term liabilities	10	**9,302**	8,686
Deferred income taxes		**10,539**	10,183
		45,891	36,123
SHAREHOLDERS' EQUITY			
Share capital	12	**11,064**	10,712
Retained earnings		**28,103**	28,948
Accumulated other comprehensive income	13	**301**	172
		39,468	39,832
		$ 85,359	$ 75,955

Commitments and contingencies (note 17)

Approved by the Board of Directors on March 5, 2025.

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian dollars, except per common share amounts, unaudited)	Note	Three Months Ended Dec 31 2024	Three Months Ended Dec 31 2023	Year Ended Dec 31 2024	Year Ended Dec 31 2023
Product sales	18	**$ 11,064**	$ 10,679	**$ 41,509**	$ 40,835
Less: royalties		**(1,596)**	(1,126)	**(5,853)**	(4,867)
Revenue		**9,468**	9,553	**35,656**	35,968
Expenses					
Production		**2,008**	2,056	**8,093**	8,480
Transportation, blending and feedstock		**2,700**	2,349	**9,984**	9,302
Depletion, depreciation and amortization	4,5,6	**1,901**	2,061	**6,681**	6,413
Administration		**127**	119	**503**	452
Share-based compensation	10	**44**	57	**279**	491
Asset retirement obligation accretion	10	**98**	91	**389**	366
Interest and other financing expense		**142**	117	**592**	636
Risk management loss (gain)	16	**142**	(24)	**177**	(2)
Foreign exchange loss (gain)		**720**	(265)	**955**	(279)
Loss (gain) from investments	7	**—**	34	**(56)**	(56)
		7,882	6,595	**27,597**	25,803
Earnings before taxes		**1,586**	2,958	**8,059**	10,165
Current income tax expense	11	**221**	505	**1,531**	1,879
Deferred income tax expense (recovery)	11	**227**	(174)	**422**	53
Net earnings		**$ 1,138**	$ 2,627	**$ 6,106**	$ 8,233
Net earnings per common share (1)					
Basic	15	**$ 0.54**	$ 1.22	**$ 2.87**	$ 3.77
Diluted	15	**$ 0.54**	$ 1.21	**$ 2.85**	$ 3.74

(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 **Dec 31 2024**	Three Months Ended Dec 31 2023	Year Ended **Dec 31 2024**	Year Ended Dec 31 2023
Net earnings	**$ 1,138**	$ 2,627	**$ 6,106**	$ 8,233
Items that may be reclassified subsequently to net earnings				
Net change in derivative financial instruments designated as cash flow hedges				
Unrealized income during the period, net of taxes of $nil (2023 – $nil) – three months ended; $nil (2023 – $nil) – year ended	**1**	—	**2**	2
Reclassification to net earnings, net of taxes of $nil (2023 – $nil) – three months ended; $nil (2023 – $nil) – year ended	**(1)**	—	**(4)**	(5)
	—	—	**(2)**	(3)
Foreign currency translation adjustment				
Translation of net investment	**101**	(36)	**131**	(34)
Other comprehensive income (loss), net of taxes	**101**	(36)	**129**	(37)
Comprehensive income	**$ 1,239**	$ 2,591	**$ 6,235**	$ 8,196

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian dollars, unaudited)	Note	Year Ended Dec 31 2024	Year Ended Dec 31 2023
Share capital	12		
Balance – beginning of year		**$ 10,712**	$ 10,294
Issued upon exercise of stock options		**280**	372
Previously recognized liability on stock options exercised for common shares		**358**	435
Purchase of common shares under Normal Course Issuer Bid		**(286)**	(389)
Balance – end of year		**11,064**	10,712
Retained earnings			
Balance – beginning of year		**28,948**	27,672
Net earnings		**6,106**	8,233
Dividends on common shares	12	**(4,537)**	(4,028)
Purchase of common shares under Normal Course Issuer Bid, including tax	12	**(2,414)**	(2,929)
Balance – end of year		**28,103**	28,948
Accumulated other comprehensive income	13		
Balance – beginning of year		**172**	209
Other comprehensive income (loss), net of taxes		**129**	(37)
Balance – end of year		**301**	172
Shareholders' equity		**$ 39,468**	$ 39,832

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended		Year Ended	
(millions of Canadian dollars, unaudited)	Note	**Dec 31 2024**	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Operating activities					
Net earnings		**$ 1,138**	$ 2,627	**$ 6,106**	$ 8,233
Non-cash items					
Depletion, depreciation and amortization	4,5,6	**1,901**	2,061	**6,681**	6,413
Share-based compensation		**44**	57	**279**	491
Asset retirement obligation accretion		**98**	91	**389**	366
Unrealized risk management (gain) loss		**(4)**	(7)	**9**	12
Unrealized foreign exchange loss (gain)		**782**	(276)	**888**	(260)
Loss (gain) from investments	7	**—**	40	**(50)**	(34)
Deferred income tax expense (recovery)		**227**	(174)	**422**	53
Realized foreign exchange loss on repayment of US dollar debt securities		**—**	—	**135**	—
Abandonment expenditures	10	**(151)**	(149)	**(646)**	(509)
Other		**(40)**	(17)	**(84)**	5
Net change in non-cash working capital		**(563)**	562	**(743)**	(2,417)
Cash flows from operating activities		**3,432**	4,815	**13,386**	12,353
Financing activities					
Issuance (repayment) of bank credit facilities and commercial paper, net	9	**5,466**	(202)	**5,466**	—
Issuance of other long-term debt	9	**2,639**	—	**2,639**	—
Repayment of other long-term debt	9	**—**	(405)	**(1,008)**	(416)
Payment of lease liabilities	6	**(84)**	(79)	**(325)**	(285)
Issue of common shares on exercise of stock options	12	**32**	98	**280**	372
Dividends on common shares		**(1,110)**	(980)	**(4,429)**	(3,891)
Purchase of common shares under Normal Course Issuer Bid	12	**(551)**	(1,549)	**(2,660)**	(3,318)
Cash flows from (used in) financing activities		**6,392**	(3,117)	**(37)**	(7,538)
Investing activities					
Net expenditures on exploration and evaluation assets	4,18	**(19)**	(12)	**(92)**	(44)
Net expenditures on property, plant and equipment	5,18	**(1,281)**	(963)	**(5,291)**	(4,865)
Acquisition of Chevron's assets	4,5,18	**(9,163)**	—	**(9,163)**	—
Net proceeds from investments	7	**—**	—	**575**	—
Net change in non-cash working capital		**49**	29	**(124)**	51
Cash flows used in investing activities		**(10,414)**	(946)	**(14,095)**	(4,858)
(Decrease) increase in cash and cash equivalents		**(590)**	752	**(746)**	(43)
Cash and cash equivalents – beginning of period		**721**	125	**877**	920
Cash and cash equivalents – end of period		**$ 131**	$ 877	**$ 131**	$ 877
Interest paid on long-term debt		**$ 105**	$ 112	**$ 586**	$ 602
Income taxes paid, net		**$ 187**	$ 761	**$ 1,144**	$ 3,317

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, 2023, except as disclosed in note 2. These interim consolidated financial statements contain disclosures that are supplemental to the Company's annual audited consolidated financial statements. Certain disclosures normally required to be included in the notes to the annual audited consolidated financial statements have been condensed. These interim consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2023.

Critical Accounting Estimates and Judgements

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

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. CHANGE IN ACCOUNTING POLICIES

In January 2020, the IASB issued amendments to IAS 1 "Presentation of Financial Statements" to clarify that liabilities are classified as either current or non-current, depending on the existence of the substantive right at the end of the reporting period for an entity to defer settlement of the liability for at least twelve months after the reporting period. In October 2022, the IASB issued further amendments to specify that the classification of debt as current or non-current at the reporting date is not affected by covenants to be complied with after the reporting date. The amendments were adopted on January 1, 2024 and had no impact on the Company's interim consolidated financial statements.

3. ACCOUNTING STANDARDS ISSUED BUT NOT YET APPLIED

In April 2024, the IASB issued IFRS 18 "Presentation and Disclosure in Financial Statements", which provides presentation and disclosure requirements for the primary financial statements and related notes, replacing IAS 1 "Presentation of Financial Statements". IFRS 18 introduces defined categories for income and expenses and requires disclosure of new defined subtotals, including operating profit. The new standard also requires additional notes for management-defined performance measures and disclosure of certain expenses by nature. There are some associated changes to the statement of cash flows, including the starting point for the calculation of cash flows from operating activities and the categorization of interest and dividends. IFRS 18 is effective January 1, 2027, with early adoption permitted. The new standard is required to be adopted retrospectively. The Company is assessing the impact of IFRS 18 on the Company's consolidated financial statements.

In May 2024, the IASB issued amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled using an electronic payment system. The amendments also clarify the requirements for assessing whether a financial asset meets the solely payments of principal and interest criterion, and adds disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments are effective January 1, 2026, with early adoption permitted. The amendments are required to be adopted retrospectively by adjusting the opening balance of financial assets, financial liabilities and retained earnings at the date of adoption. The Company is assessing the impact of the amendments on the Company's consolidated financial statements.

4. EXPLORATION AND EVALUATION ASSETS

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	**North Sea**	**Offshore Africa**		
Cost					
At December 31, 2023	$ 2,031	$ —	$ 100	$ 77	$ 2,208
Additions, net	**102**	**—**	**6**	**—**	**108**
Acquisition of Chevron's assets (note 5)	**320**	**—**	**—**	**—**	**320**
Transfers to property, plant and equipment	**(45)**	**—**	**—**	**(7)**	**(52)**
Derecognitions and other (1)	**—**	**—**	**(62)**	**—**	**(62)**
Foreign exchange adjustments	**—**	**—**	**4**	**—**	**4**
At December 31, 2024	**$ 2,408**	**$ —**	**$ 48**	**$ 70**	**$ 2,526**

(1) In connection with the Company's notice of withdrawal from Block 11B/12B in South Africa in the second quarter of 2024, the Company derecognized $62 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

In December 2024, the Company completed the acquisition of Chevron Canada Limited's ("Chevron") assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments, including exploration and evaluation assets of $320 million. Refer to note 5 for further details on the acquisition.

5. PROPERTY, PLANT AND EQUIPMENT

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
Cost							
At December 31, 2023	$ 83,483	$ 8,606	$ 4,409	$ 49,375	$ 484	$ 566	$ 146,923
Additions	**3,100**	**39**	**197**	**1,928**	**11**	**41**	**5,316**
Acquisition of Chevron's assets	**2,585**	**—**	**—**	**6,316**	**—**	**—**	**8,901**
Transfers from exploration and evaluation assets	**45**	**—**	**—**	**7**	**—**	**—**	**52**
Change in ARO estimates	**340**	**313**	**8**	**175**	**—**	**—**	**836**
Derecognitions (1)	**(589)**	**(18)**	**—**	**(456)**	**—**	**—**	**(1,063)**
Foreign exchange adjustments and other	**—**	**791**	**409**	**—**	**—**	**—**	**1,200**
At December 31, 2024	**$ 88,964**	**$ 9,731**	**$ 5,023**	**$ 57,345**	**$ 495**	**$ 607**	**$ 162,165**
Accumulated depletion and depreciation							
At December 31, 2023	$ 58,840	$ 8,382	$ 3,358	$ 11,105	$ 213	$ 444	$ 82,342
Expense	**3,741**	**96**	**192**	**2,086**	**16**	**26**	**6,157**
Derecognitions (1)	**(589)**	**(18)**	**—**	**(456)**	**—**	**—**	**(1,063)**
Recoverability charge (2)	**—**	**160**	**—**	**—**	**—**	**—**	**160**
Foreign exchange adjustments and other	**18**	**772**	**335**	**30**	**—**	**—**	**1,155**
At December 31, 2024	**$ 62,010**	**$ 9,392**	**$ 3,885**	**$ 12,765**	**$ 229**	**$ 470**	**$ 88,751**
Net book value							
At December 31, 2024	**$ 26,954**	**$ 339**	**$ 1,138**	**$ 44,580**	**$ 266**	**$ 137**	**$ 73,414**
At December 31, 2023	$ 24,643	$ 224	$ 1,051	$ 38,270	$ 271	$ 122	$ 64,581

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

(2) The Company continues to refine its project scope and cost estimates related to its long-term abandonment activities at the Ninian field in the North Sea. At December 31, 2024, the Company recognized a non-cash charge of $21 million, net of tax recoveries (December 31, 2023 - $113 million, net of tax recoveries), comprised of a recoverability charge recognized in depletion, depreciation and amortization expense, net of deferred tax recoveries of $139 million (December 31, 2023 - $323 million). The Company's estimate of its asset retirement obligation liability, including the Ninian field recoverability charges and associated tax recoveries, is subject to revision in future periods as abandonment efforts progress.

Acquisition of Chevron's Assets

In December 2024, the Company completed the acquisition of Chevron's assets for total cash consideration of $9,163 million, subject to final closing adjustments. The acquisition includes a 70% operated working interest in the light crude oil and liquids-rich Duvernay asset play in Alberta and a 20% working interest in AOSP. As a result of the acquisition, the Company now has a 90% direct and indirect working interest in AOSP, which includes the Muskeg River and Jackpine mines, the Scotford Upgrader, and the Quest Carbon Capture and Storage facility ("Quest"). The acquisition also includes various working interests in a number of other non-producing oil sands leases. The Company consolidates its interests in the assets, liabilities, revenue, and expenses of both the AOSP and Duvernay joint operations.

In connection with the acquisition, the Company arranged a fully committed $4,000 million non-revolving term credit facility maturing December 2027 (note 9), and assumed certain product transportation and processing commitments (note 17).

The acquisition has been accounted for as a business combination using the acquisition method of accounting. The allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities acquired as at the acquisition date. Key assumptions used in the determination of estimated fair value were future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates, and income taxes. The fair value of working capital approximates its carrying value. The below amounts are estimates, and may be subject to change based on the receipt of new information.

The following provides a summary of the net assets acquired relating to the acquisition:

Property, plant and equipment	$	8,901
Exploration and evaluation assets		320
Working capital		115
Asset retirement obligations		(173)
Net assets acquired	$	9,163

As a result of the acquisition, revenue increased by approximately $222 million to $35,656 million and net operating income (comprised of revenue less production, and transportation, blending and feedstock expenses) increased by approximately $109 million to $17,579 million for the year ended December 31, 2024. Including the impact of interest expense and depletion, depreciation and amortization, earnings before tax increased by approximately $23 million for the year ended December 31, 2024.

If the acquisition had been completed on January 1, 2024, the Company estimates that pro forma revenue would have increased by approximately $2,700 million and pro forma net operating income would have increased by approximately $1,475 million for the year ended December 31, 2024. Including the impact of interest expense and depletion, depreciation and amortization, the Company estimates earnings before tax would have increased by approximately $570 million for the year ended December 31, 2024. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2024, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

Other Matters

As at December 31, 2024, the Company determined that there were no indicators of impairment with respect to its property, plant and equipment. Although there were no indicators of impairment, the Company completed its normal course assessment of the recoverability of its property, plant and equipment and exploration and evaluation assets, and determined the carrying amounts of all its cash generating units to be recoverable, except for certain North Sea property, plant and equipment where recoverability charges have been recognized related to ongoing abandonment activities at the Ninian field.

6. LEASES

Lease assets

		Product transportation and storage		Field equipment and power		Offshore vessels and equipment		Office leases and other		Total
At December 31, 2023	$	840	$	482	$	71	$	65	$	1,458
Additions		**5**		**118**		**40**		**68**		**231**
Depreciation		**(96)**		**(135)**		**(51)**		**(20)**		**(302)**
Foreign exchange adjustments and other		**3**		**3**		**4**		**(3)**		**7**
At December 31, 2024	**$**	**752**	**$**	**468**	**$**	**64**	**$**	**110**	**$**	**1,394**

Lease liabilities

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at December 31, 2024 were as follows:

	Dec 31 2024	Dec 31 2023
Lease liabilities	**$ 1,464**	$ 1,555
Less: current portion	**255**	298
	$ 1,209	$ 1,257

Total cash outflows for leases for the three months ended December 31, 2024, including payments related to short-term leases not reported as lease assets, were $346 million (three months ended December 31, 2023 – $302 million; year ended December 31, 2024 – $1,333 million; year ended December 31, 2023 – $1,325 million). Interest expense on leases for the three months ended December 31, 2024 was $16 million (three months ended December 31, 2023 – $16 million; year ended December 31, 2024 – $69 million; year ended December 31, 2023 – $64 million).

7. INVESTMENTS

During the second quarter of 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. ("PrairieSky") for $25.65 per common share with net proceeds at close, after fees and expenses, of $575 million. During the year ended December 31, 2024, the Company realized a $50 million gain on the investment in PrairieSky and dividend income of $6 million.

8. OTHER LONG-TERM ASSETS

	Dec 31 2024	Dec 31 2023
Long-term prepayments, contracts and other (1)	**$ 313**	$ 279
Prepaid cost of service tolls	**166**	179
Long-term inventory	**204**	141
Risk management (note 16)	**13**	13
	696	612
Less: current portion	**76**	71
	$ 620	$ 541

(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 50,000 barrels per day bitumen upgrader and refinery that processes approximately 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 17). Sales of diesel and refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 18).

During the third quarter of 2024, NWRP repaid $500 million of 3.20% series A bonds.

During the second quarter of 2024, NWRP issued $700 million of 4.85% series P bonds due June 2034 and $600 million of 5.08% series Q bonds due June 2054.

During the second quarter of 2024, NWRP amended its syndicated credit facility to extend the revolving facility originally maturing June 2025 to June 2027, reduce the availability on the revolving facility from $2,175 million to $1,900 million, and reduce the availability of the non-revolving facility from $940 million to $500 million. Additionally, in the third and fourth quarter of 2024, NWRP repaid an additional $150 million and $100 million, respectively, on the non-revolving facility, reducing the availability to $250 million.

The carrying value of the Company's interest in NWRP is $nil, and as at December 31, 2024, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $509 million (December 31, 2023 – $555 million). For the three months ended December 31, 2024, the Company's recovery of its share of unrecognized equity losses was $1 million (year ended December 31, 2024 – recovery of unrecognized equity losses of $46 million; three months ended December 31, 2023 – unrecognized equity loss of $5 million; year ended December 31, 2023 – unrecognized equity loss of $4 million).

9. LONG-TERM DEBT

	Dec 31 2024	Dec 31 2023
Canadian dollar denominated debt, unsecured		
Medium-term notes	**$ 1,466**	$ 1,286
US dollar denominated debt, unsecured		
Bank credit facilities (December 31, 2024 – US$3,393 million; December 31, 2023 – US$nil)	**4,888**	—
Commercial paper (December 31, 2024 – US$467 million; December 31, 2023 – US$nil)	**672**	—
US dollar debt securities (December 31, 2024 – US$8,250 million; December 31, 2023 – US$7,250 million)	**11,883**	9,573
	18,909	10,859
Less: original issue discounts, net [1]	**12**	11
transaction costs [1] [2]	**78**	49
	18,819	10,799
Less: current portion of commercial paper	**672**	—
current portion of long-term debt [1] [2]	**1,728**	980
	$ 16,419	$ 9,819

(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 December 31, 2024, the Company had undrawn revolving bank credit facilities of $4,562 million. Additionally, the Company had in place a fully drawn 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 December 31, 2024, the Company had $672 million drawn under its commercial paper program, and reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

- a $100 million demand credit facility;
- a $500 million revolving credit facility, maturing February 2026;
- 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 fourth quarter of 2024, the Company extended its $2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028, and its $500 million revolving credit facility from February 2025 to February 2026.

During the fourth quarter of 2024 and in connection with the acquisition of Chevron's assets, the Company entered into a $4,000 million non-revolving term credit facility maturing December 2027 (note 5).

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 year ended December 31, 2024 was 5.4% (December 31, 2023 – N/A), and on total long-term debt outstanding for the year ended December 31, 2024 was 4.9% (December 31, 2023 – 4.8%).

As at December 31, 2024, letters of credit and guarantees aggregating to $1,542 million were outstanding (December 31, 2023 – $446 million).

Medium-Term Notes

During the fourth quarter of 2024, the Company issued, by private placement, $500 million of 4.15% medium-term notes due December 2031.

During the second quarter of 2024, the Company repaid $320 million of 3.55% 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. During 2024, no medium-term notes were issued in Canada under the base shelf prospectus.

US Dollar Debt Securities

During the fourth quarter of 2024, the Company issued, by private placement, US$750 million of 5.00% notes due December 2029 and US$750 million of 5.40% notes due December 2034.

Subsequent to December 31, 2024, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.

During the second quarter of 2024, the Company repaid US$500 million of 3.80% US dollar debt securities.

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. During 2024, no US dollar debt securities were issued in the United States under the base shelf prospectus.

10. OTHER LONG-TERM LIABILITIES

	Dec 31 2024	Dec 31 2023
Asset retirement obligations	**$ 8,607**	$ 7,690
Lease liabilities (note 6)	**1,464**	1,555
Share-based compensation	**620**	780
Transportation and processing contracts	**58**	87
Risk management (note 16)	**8**	4
Other	**80**	73
	10,837	10,189
Less: current portion	**1,535**	1,503
	$ 9,302	$ 8,686

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, 2023 – 5.2%) and inflation rates of up to 2% (December 31, 2023 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	Dec 31 2024	Dec 31 2023
Balance – beginning of year	**$ 7,690**	$ 6,908
Liabilities incurred	**28**	25
Liabilities acquired, net	**171**	—
Liabilities settled	**(646)**	(509)
Asset retirement obligation accretion	**389**	366
Revision of cost, inflation and timing estimates (1)	**417**	621
Change in discount rates	**419**	314
Foreign exchange adjustments	**139**	(35)
Balance – end of year	**8,607**	7,690
Less: current portion	**787**	634
	$ 7,820	$ 7,056

(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.

	Dec 31 2024	Dec 31 2023
Balance – beginning of year	**$ 780**	$ 832
Share-based compensation expense	**279**	491
Cash payment for stock options surrendered and PSUs vested	**(84)**	(110)
Transferred to common shares	**(358)**	(435)
Other	**3**	2
Balance – end of year	**620**	780
Less: current portion	**463**	538
	$ 157	$ 242

11. INCOME TAXES

The provision for income tax was as follows:

Expense (recovery)	Three Months Ended Dec 31 2024	Three Months Ended Dec 31 2023	Year Ended Dec 31 2024	Year Ended Dec 31 2023
Current corporate income tax – North America [1]	**$ 261**	$ 487	**$ 1,654**	$ 1,853
Current corporate income tax – North Sea	**(11)**	3	**(41)**	(6)
Current corporate income tax – Offshore Africa	**35**	20	**57**	73
Current PRT [2] – North Sea	**(67)**	(13)	**(134)**	(58)
Other taxes	**3**	8	**(5)**	17
Current income tax	**221**	505	**1,531**	1,879
Deferred corporate income tax	**372**	64	**520**	267
Deferred PRT [2] – North Sea	**(145)**	(238)	**(98)**	(214)
Deferred income tax	**227**	(174)	**422**	53
Income tax	**$ 448**	$ 331	**$ 1,953**	$ 1,932

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

As at December 31, 2024, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of $50 million (December 31, 2023 – $118 million) and a deferred PRT recovery of $89 million (December 31, 2023 – $205 million) in connection with the increase in the Company's estimate of future abandonment costs for the planned decommissioning activities at the Ninian field in the North Sea.

12. SHARE CAPITAL

Authorized

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

Issued Common Shares[1]	Year Ended Dec 31, 2024 Number of shares (thousands)	Amount
Balance – beginning of year	**2,144,815**	**$ 10,712**
Issued upon exercise of stock options	**13,531**	**280**
Previously recognized liability on stock options exercised for common shares	**—**	**358**
Purchase of common shares under Normal Course Issuer Bid	**(55,350)**	**(286)**
Balance – end of year	**2,102,996**	**$ 11,064**

Dividends[1]

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 payable 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, beginning with the dividend paid on January 3, 2025. On February 28, 2024, the Board of Directors approved a 5% increase in the quarterly dividend to $0.525 per common share.

On November 1, 2023, the Board of Directors approved an 11% increase in the quarterly dividend to $0.50 per common share. On March 1, 2023, the Board of Directors approved a 6% increase in the quarterly dividend to $0.45 per common share.

(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).

Normal Course Issuer Bid[(1)]

On March 8, 2024, 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 180,462,858 common shares, representing 10% of the public float, over a 12-month period commencing March 13, 2024 and ending March 12, 2025.

For the year ended December 31, 2024, the Company purchased 55,350,000 common shares at a weighted average price of $48.07 per common share for a total cost, including tax, of $2,700 million. Retained earnings were reduced by $2,414 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2024, up to and including March 4, 2025, the Company purchased 7,740,000 common shares at a weighted average price of $44.11 per common share for a total cost, including tax, of $344 million.

On March 5, 2025, the Board of Directors approved a resolution authorizing the Company to file a Notice of Intention with the TSX to purchase, by way of Normal Course Issuer Bid, up to 10% of the public float (as determined in accordance with the rules of the TSX) of its issued and outstanding common shares. Subject to acceptance of the Notice of Intention by the TSX, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

Share-Based Compensation – Stock Options[(1)]

The following table summarizes information relating to stock options outstanding as at December 31, 2024:

	Stock options (thousands)	**Weighted average exercise price**
Outstanding – beginning of year	**52,410**	**$ 26.80**
Granted	**15,906**	**$ 44.82**
Exercised for common shares	**(13,531)**	**$ 20.69**
Surrendered for cash settlement	**(384)**	**$ 22.19**
Forfeited	**(3,595)**	**$ 29.69**
Outstanding – end of year	**50,806**	**$ 33.90**
Exercisable – end of year	**10,033**	**$ 26.67**

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.

13. ACCUMULATED OTHER COMPREHENSIVE INCOME

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

	Dec 31 2024	Dec 31 2023
Derivative financial instruments designated as cash flow hedges	**$ 70**	$ 72
Foreign currency translation adjustment	**231**	100
	$ 301	$ 172

(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).

14. CAPITAL DISCLOSURES

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and 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 December 31, 2024, the ratio was within the target range at 32.1%.

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.

	Dec 31 2024	Dec 31 2023
Long-term debt	**$ 18,819**	$ 10,799
Less: cash and cash equivalents	**131**	877
Long-term debt, net	**$ 18,688**	$ 9,922
Total shareholders' equity	**$ 39,468**	$ 39,832
Debt to book capitalization	**32.1%**	19.9%

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 December 31, 2024, the Company was in compliance with this covenant.

15. NET EARNINGS PER COMMON SHARE[(1)]

		Three Months Ended		Year Ended	
		Dec 31 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Weighted average common shares outstanding – basic (thousands of shares)		**2,108,047**	2,159,647	**2,125,804**	2,182,623
Effect of dilutive stock options (thousands of shares)		**12,336**	20,005	**14,625**	21,625
Weighted average common shares outstanding – diluted (thousands of shares)		**2,120,383**	2,179,652	**2,140,429**	2,204,248
Net earnings		**$ 1,138**	$ 2,627	**$ 6,106**	$ 8,233
Net earnings per common share	– basic	**$ 0.54**	$ 1.22	**$ 2.87**	$ 3.77
	– diluted	**$ 0.54**	$ 1.21	**$ 2.85**	$ 3.74

(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).

16. FINANCIAL INSTRUMENTS

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

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

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

Asset (liability)	**Dec 31 2024**	Dec 31 2023
Balance – beginning of year	**$ 9**	$ 6
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities [1] [2] [3]	**(6)**	3
Foreign exchange	**1**	—
Other comprehensive income	**1**	—
Balance – end of year	**5**	9
Less: current portion	**5**	8
	$ —	$ 1

(1) Risk management assets and liabilities are disclosed in note 8 and note 10, respectively.

(2) 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.

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

	Three Months Ended		Year Ended	
	Dec 31 2024	Dec 31 2023	**Dec 31 2024**	Dec 31 2023
Net realized risk management loss (gain)	**$ 146**	$ (17)	**$ 168**	$ (14)
Net unrealized risk management (gain) loss	**(4)**	(7)	**9**	12
	$ 142	$ (24)	**$ 177**	$ (2)

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:

	Dec 31, 2024	
	Carrying amount	**Level 1 Fair Value**
Fixed rate long-term debt [1] [2]	**$ 13,259**	**$ 13,186**

(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, 2023.

a) Market risk

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

Commodity price risk management

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

Interest rate risk management

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. As at December 31, 2024, 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.

As at December 31, 2024, the Company had US$2,187 million of foreign currency forward contracts outstanding (December 31, 2023 – US$1,003 million), with original terms of up to 90 days, of which US$1,521 million were designated as derivatives held for trading (December 31, 2023 – US$1,003 million) and US$666 million were designated as cash flow hedges (December 31, 2023 – US$nil).

b) Credit risk

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

Counterparty credit risk management

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at December 31, 2024, 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 December 31, 2024, 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	$ 1,079	$ —	$ —	$ —
Accrued liabilities	$ 4,525	$ —	$ —	$ —
Long-term debt (1)	$ 2,400	$ 941	$ 7,494	$ 8,074
Other long-term liabilities (2)	$ 263	$ 187	$ 405	$ 617
Interest and other financing expense (3)	$ 1,024	$ 951	$ 1,978	$ 3,574

(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, $187 million; two to less than five years, $405 million; and thereafter, $617 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 December 31, 2024.

17. COMMITMENTS AND CONTINGENCIES

In the normal course of business, the Company has committed to certain payments. The following table summarizes the Company's commitments as at December 31, 2024:

	2025	2026	2027	2028	2029	Thereafter
Product transportation, purchases and processing (1) (2) (3)	$ 2,249	$ 2,245	$ 2,097	$ 1,983	$ 1,882	$ 19,310
North West Redwater Partnership service toll (4)	$ 141	$ 121	$ 103	$ 104	$ 104	$ 4,203
Offshore vessels and equipment	$ 88	$ —	$ —	$ —	$ —	$ —
Field equipment and power (3)	$ 43	$ 29	$ 29	$ 28	$ 27	$ 216
Other	$ 124	$ 111	$ 21	$ 22	$ 21	$ 247

(1) The Company's commitment for the 20-year product transportation agreement 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) During the third quarter of 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(3) The acquisition of Chevron's assets in the fourth quarter of 2024 included approximately $1,292 million of product transportation and processing commitments and approximately $75 million of field equipment and power commitments (note 5).

(4) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $2,161 million of interest payable over the 40-year tolling period, ending in 2058 (note 8).

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

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

18. SEGMENTED INFORMATION

	North America				North Sea				Offshore Africa				Total Exploration and Production			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
(millions of Canadian dollars, unaudited)	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales																
Crude oil and NGLs	**$ 4,830**	$ 4,451	**$ 18,740**	$ 17,375	**$ 102**	$ 163	**$ 467**	$ 435	**$ 67**	$ 176	**$ 434**	$ 577	**$ 4,999**	$ 4,790	**$ 19,641**	$ 18,387
Natural gas	**414**	560	**1,415**	2,375	**3**	2	**7**	7	**8**	13	**42**	51	**425**	575	**1,464**	2,433
Other income and revenue [1]	**16**	5	**6**	10	**—**	—	**4**	—	**1**	2	**4**	9	**17**	7	**14**	19
Total segmented product sales	**5,260**	5,016	**20,161**	19,760	**105**	165	**478**	442	**76**	191	**480**	637	**5,441**	5,372	**21,119**	20,839
Less: royalties	**(756)**	(585)	**(2,876)**	(2,443)	**—**	—	**(1)**	(1)	**(4)**	(18)	**(24)**	(57)	**(760)**	(603)	**(2,901)**	(2,501)
Segmented revenue	**4,504**	4,431	**17,285**	17,317	**105**	165	**477**	441	**72**	173	**456**	580	**4,681**	4,769	**18,218**	18,338
Segmented expenses																
Production	**759**	830	**3,249**	3,617	**121**	129	**440**	342	**23**	47	**109**	141	**903**	1,006	**3,798**	4,100
Transportation, blending and feedstock	**1,609**	1,530	**6,184**	5,808	**1**	1	**10**	7	**1**	—	**1**	1	**1,611**	1,531	**6,195**	5,816
Depletion, depreciation and amortization	**1,010**	971	**3,831**	3,679	**221**	466	**279**	494	**46**	66	**297**	213	**1,277**	1,503	**4,407**	4,386
Asset retirement obligation accretion	**58**	58	**231**	234	**17**	12	**65**	46	**3**	2	**9**	8	**78**	72	**305**	288
Risk management loss (commodity derivatives)	**—**	7	**7**	24	**—**	—	**—**	—	**—**	—	**—**	—	**—**	7	**7**	24
Total segmented expenses	**3,436**	3,396	**13,502**	13,362	**360**	608	**794**	889	**73**	115	**416**	363	**3,869**	4,119	**14,712**	14,614
Segmented earnings (loss)	**$ 1,068**	$ 1,035	**$ 3,783**	$ 3,955	**$ (255)**	$ (443)	**$ (317)**	$ (448)	**$ (1)**	$ 58	**$ 40**	$ 217	**$ 812**	$ 650	**$ 3,506**	$ 3,724
Non-segmented expenses																
Administration																
Share-based compensation																
Interest and other financing expense																
Risk management loss (gain) (other)																
Foreign exchange loss (gain)																
Loss (gain) from investments																
Total non-segmented expenses																
Earnings before taxes																
Current income tax																
Deferred income tax																
Net earnings																

(millions of Canadian dollars, unaudited)	Oil Sands Mining and Upgrading				Midstream and Refining				Inter–segment Elimination and Other				Total			
	Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31		Three Months Ended Dec 31		Year Ended Dec 31	
	2024	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Segmented product sales																
Crude oil and NGLs [2]	**$ 5,362**	$ 5,042	**$ 19,263**	$ 18,661	**$ 21**	$ 20	**$ 82**	$ 76	**$ (1)**	$ (23)	**$ 98**	$ 176	**$ 10,381**	$ 9,829	**$ 39,084**	$ 37,300
Natural gas	**—**	—	**—**	—	**—**	—	**—**	—	**26**	28	**104**	142	**451**	603	**1,568**	2,575
Other income and revenue [1]	**19**	3	**16**	5	**193**	236	**813**	926	**3**	1	**14**	10	**232**	247	**857**	960
Total segmented product sales	**5,381**	5,045	**19,279**	18,666	**214**	256	**895**	1,002	**28**	6	**216**	328	**11,064**	10,679	**41,509**	40,835
Less: royalties	**(836)**	(523)	**(2,952)**	(2,366)	**—**	—	**—**	—	**—**	—	**—**	—	**(1,596)**	(1,126)	**(5,853)**	(4,867)
Segmented revenue	**4,545**	4,522	**16,327**	16,300	**214**	256	**895**	1,002	**28**	6	**216**	328	**9,468**	9,553	**35,656**	35,968
Segmented expenses																
Production	**1,019**	947	**3,921**	3,989	**70**	89	**315**	332	**16**	14	**59**	59	**2,008**	2,056	**8,093**	8,480
Transportation, blending and feedstock [2]	**915**	663	**2,959**	2,563	**164**	166	**685**	664	**10**	(11)	**145**	259	**2,700**	2,349	**9,984**	9,302
Depletion, depreciation and amortization	**621**	554	**2,258**	2,011	**3**	4	**16**	16	**—**	—	**—**	—	**1,901**	2,061	**6,681**	6,413
Asset retirement obligation accretion	**20**	19	**84**	78	**—**	—	**—**	—	**—**	—	**—**	—	**98**	91	**389**	366
Risk management loss (commodity derivatives)	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	—	**—**	7	**7**	24
Total segmented expenses	**2,575**	2,183	**9,222**	8,641	**237**	259	**1,016**	1,012	**26**	3	**204**	318	**6,707**	6,564	**25,154**	24,585
Segmented earnings (loss)	**$ 1,970**	$ 2,339	**$ 7,105**	$ 7,659	**$ (23)**	$ (3)	**$ (121)**	$ (10)	**$ 2**	$ 3	**$ 12**	$ 10	**$ 2,761**	$ 2,989	**$ 10,502**	$ 11,383
Non-segmented expenses																
Administration													**127**	119	**503**	452
Share-based compensation													**44**	57	**279**	491
Interest and other financing expense													**142**	117	**592**	636
Risk management loss (gain) (other)													**142**	(31)	**170**	(26)
Foreign exchange loss (gain)													**720**	(265)	**955**	(279)
Loss (gain) from investments													**—**	34	**(56)**	(56)
Total non-segmented expenses													**1,175**	31	**2,443**	1,218
Earnings before taxes													**1,586**	2,958	**8,059**	10,165
Current income tax													**221**	505	**1,531**	1,879
Deferred income tax													**227**	(174)	**422**	53
Net earnings													**$ 1,138**	$ 2,627	**$ 6,106**	$ 8,233

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

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

Capital Expenditures[1]

	Year Ended					
	Dec 31, 2024			Dec 31, 2023		
	Net expenditures	**Non-cash and fair value changes [2]**	**Capitalized costs**	Net expenditures	Non-cash and fair value changes [2]	Capitalized costs
Exploration and evaluation assets						
Exploration and Production						
North America [3]	**$ 406**	**$ (29)**	**$ 377**	$ 41	$ (36)	$ 5
Offshore Africa	**6**	**(62)**	**(56)**	3	—	3
Oil Sands Mining and Upgrading [3]	**—**	**(7)**	**(7)**	—	(25)	(25)
	412	**(98)**	**314**	44	(61)	(17)
Property, plant and equipment						
Exploration and Production						
North America [3]	**5,627**	**(146)**	**5,481**	2,729	(321)	2,408
North Sea	**39**	**295**	**334**	33	525	558
Offshore Africa	**197**	**8**	**205**	169	18	187
	5,863	**157**	**6,020**	2,931	222	3,153
Oil Sands Mining and Upgrading [3]	**8,104**	**(134)**	**7,970**	1,894	(251)	1,643
Midstream and Refining	**11**	**—**	**11**	10	—	10
Head Office	**41**	**—**	**41**	30	—	30
	14,019	**23**	**14,042**	4,865	(29)	4,836
	$ 14,431	**$ (75)**	**$ 14,356**	$ 4,909	$ (90)	$ 4,819

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

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

(3) Includes cash consideration paid of $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.

Segmented Assets

	Dec 31 2024	Dec 31 2023
Exploration and Production		
North America	**$ 32,670**	$ 30,058
North Sea	**702**	602
Offshore Africa	**1,412**	1,380
Other	**31**	32
Oil Sands Mining and Upgrading	**49,221**	42,865
Midstream and Refining	**1,099**	856
Head Office	**224**	162
	$ 85,359	$ 75,955

19. SUBSEQUENT EVENTS

On January 29, 2025, the Company announced that pursuant to an agreement with Shell Canada Limited and affiliates ("Shell") and as a result of certain conditions being met, the Company will acquire a 10% working interest in the AOSP mines, associated reserves and additional working interests in a number of other non-producing oil sands leases in exchange for a 10% working interest in the Scotford Upgrader and Quest. Following the close of the transaction, the Company will have a 100% direct working interest in the AOSP mines and an 80% interest in the Scotford Upgrader and Quest, where Shell will remain operator. The transaction does not include an exchange of cash, except for regular closing adjustments for working capital. The acquisition is targeted to close in the first half of 2025, subject to obtaining the necessary regulatory approvals.

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 December 31, 2024:	
Interest coverage (times)	
Net earnings [(1)]	14.6x
Adjusted funds flow [(2)]	28.7x

(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

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Chief Operating Officer, Oil Sands

Robin S. Zabek
Chief Operating Officer, Exploration and Production

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Senior Vice-President, Production

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Dwayne F. Giggs
Senior Vice-President, Exploration

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Senior Vice-President, Safety, Risk Management and Innovation

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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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