Canadian Natural

CANADIAN NATURAL RESOURCES LIMITED

MANAGEMENT'S DISCUSSION & ANALYSIS

FOR THE THREE MONTHS AND YEAR ENDED DECEMBER 31, 2025

MARCH 4, 2026

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, forecast and anticipated 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 maintenance of the Company's facilities and any expected return to service dates; the construction, expansion, or maintenance of third-party facilities that process the Company's products; 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, Ukraine and Venezuela, the impact of changes to US economic policy, 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; the impact of the ramp-up of LNG Canada on commodity 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 uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); 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, and the implementation of the Memorandum of Understanding ("MOU") entered into between the Government of Canada and the Government of Alberta in November 2025; civil unrest and 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 acquisition of the remaining interest in the AOSP mines and other acquisitions that occurred in 2025; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; 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 uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including the implementation of the MOU). 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. Subsequently, on November 4, 2025, the federal government tabled the 2025 Budget, which proposed further amendments to the *Competition Act*, namely removing the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminating private rights of action under the revised business-activity greenwashing provision. Uncertainty surrounding the interpretation and enforcement of this legislation, which includes the status of any proposed or future amendments, 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, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's financial statements for the three months and year ended December 31, 2025 and this MD&A have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards").

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, thermal bitumen, and SCO (including mining bitumen). 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, 2025 in relation to the comparable periods in 2024 and the third quarter of 2025. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2024, is available on SEDAR+ at www.sedarplus.ca, 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 4, 2026.

FINANCIAL HIGHLIGHTS

		Three Months Ended		Year Ended	
($ millions, except per common share amounts)		**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Product sales [1]		**$ 10,710**	$ 11,070	$ 11,064	**$ 44,167**	$ 41,509
Crude oil and NGLs		**$ 9,666**	$ 10,468	$ 10,381	**$ 40,740**	$ 39,084
Natural gas		**$ 735**	$ 399	$ 451	**$ 2,450**	$ 1,568
Net earnings		**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Per common share	– basic	**$ 2.55**	$ 0.29	$ 0.54	**$ 5.17**	$ 2.87
	– diluted	**$ 2.54**	$ 0.29	$ 0.54	**$ 5.16**	$ 2.85
Adjusted net earnings from operations [2]		**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Per common share	– basic [3]	**$ 0.82**	$ 0.86	$ 0.94	**$ 3.56**	$ 3.49
	– diluted [3]	**$ 0.82**	$ 0.86	$ 0.93	**$ 3.55**	$ 3.46
Cash flows from operating activities		**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Adjusted funds flow [2]		**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859
Per common share	– basic [3]	**$ 1.80**	$ 1.88	$ 1.99	**$ 7.39**	$ 6.99
	– diluted [3]	**$ 1.79**	$ 1.87	$ 1.97	**$ 7.37**	$ 6.94
Cash flows used in investing activities		**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Net capital expenditures [2]		**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Abandonment expenditures		**$ 201**	$ 189	$ 151	**$ 771**	$ 646

(1) Further details related to product sales are disclosed in note 16 to the financial statements.

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

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

SUMMARY OF FINANCIAL HIGHLIGHTS

Consolidated Net Earnings and Adjusted Net Earnings from Operations

Net earnings for the year ended December 31, 2025 were $10,820 million compared with $6,106 million for the year ended December 31, 2024. Net earnings for the year ended December 31, 2025 included non-operating income, net of tax, of $3,376 million compared with non-operating losses of $1,308 million for the year ended December 31, 2024 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain from investment, the gain on acquisitions, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa. Excluding these items, adjusted net earnings from operations for the year ended December 31, 2025 were $7,444 million compared with $7,414 million for the year ended December 31, 2024.

Net earnings for the fourth quarter of 2025 were $5,303 million compared with $1,138 million for the fourth quarter of 2024 and $600 million for the third quarter of 2025. Net earnings for the fourth quarter of 2025 included non-operating income, net of tax, of $3,592 million compared with non-operating losses of $839 million for the fourth quarter of 2024 and non-operating losses of $1,201 million for the third quarter of 2025 related to the effects of share-based compensation, risk management activities, fluctuations in foreign exchange rates, realized foreign exchange on financing activities, the gain on acquisitions, disposition, and remeasurement, and recoverability charges related to the North Sea and Offshore Africa. Excluding these items, adjusted net earnings from operations for the fourth quarter of 2025 were $1,711 million compared with $1,977 million for the fourth quarter of 2024 and $1,801 million for the third quarter of 2025.

The movements in net earnings and adjusted net earnings from operations for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected:

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

partially offset by:

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

The movements in net earnings and adjusted net earnings from operations for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected:

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

partially offset by:

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

The impacts of depletion, depreciation and amortization, share-based compensation, risk management activities, foreign exchange (gain) loss, the gain on acquisitions, disposition, and remeasurement, the gain from investment, and recoverability charges related to the North Sea and Offshore Africa also contributed to the movements in net earnings from the comparable periods. These items are discussed in detail in the relevant sections of this MD&A. The AOSP asset swap is discussed below, and the recoverability charges related to the North Sea and Offshore Africa are discussed in detail in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

AOSP Asset Swap Transaction

On November 1, 2025, the Company completed the AOSP asset swap with Shell Canada Limited and affiliates ("Shell"). As a result of the transaction, the Company acquired from Shell, the remaining 10% interest in the AOSP mines, associated reserves, and additional working interests in a number of other non-producing oil sands leases, and in exchange to Shell, a 10% non-operated working interest in the Scotford Upgrader ("Scotford") and Quest Carbon Capture and Storage ("Quest") facilities. As a result, the Company owns and operates 100% of the AOSP mines and retains an 80% non-operated working interest in Scotford and Quest. The transaction had an effective date of March 1, 2025.

The Company recognized a $4,989 million gain related to the transaction, comprised of a $17 million gain on acquisition representing the excess of the fair value of the net assets acquired compared to the total purchase consideration and previously held interests, a non-cash gain of $4,508 million ($3,471 million after-tax) related to the remeasurement of the previously held interest in the AOSP mines to fair value, and a non-cash gain on disposition of $464 million ($357 million after-tax) related to the disposition of the 10% interest in Scotford and Quest. Further details are disclosed in note 4 to the financial statements.

Cash Flows from Operating Activities and Adjusted Funds Flow

Cash flows from operating activities for the year ended December 31, 2025 were $15,106 million compared with $13,386 million for the year ended December 31, 2024. Cash flows from operating activities for the fourth quarter of 2025 were $3,768 million compared with $3,432 million for the fourth quarter of 2024 and $3,940 million for the third quarter of 2025. The fluctuations in cash flows from operating activities from the comparable periods were primarily due to the factors previously noted related to the fluctuations in adjusted net earnings from operations, together with the impact of net changes in non-cash working capital.

Adjusted funds flow for the year ended December 31, 2025 was $15,460 million compared with $14,859 million for the year ended December 31, 2024. Adjusted funds flow for the fourth quarter of 2025 was $3,748 million compared with $4,186 million for the fourth quarter of 2024 and $3,920 million for the third quarter of 2025. The fluctuations in adjusted funds flow from the comparable periods were primarily due to the factors noted above related to the fluctuations in cash flows from operating activities, excluding the impact of the net change in non-cash working capital, abandonment expenditures, and movements in other long-term assets, including the unamortized cost of contributions to the Company's employee bonus program, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries, and prepaid cost of service tolls.

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

Production Volumes

Record crude oil and NGLs production before royalties for the fourth quarter of 2025 of 1,215,364 bbl/d increased 12% from 1,090,002 bbl/d for the fourth quarter of 2024 and increased 3% from 1,175,604 bbl/d for the third quarter of 2025. Natural gas production before royalties for the fourth quarter of 2025 of 2,660 MMcf/d increased 17% from 2,283 MMcf/d for the fourth quarter of 2024 and was comparable with 2,668 MMcf/d for the third quarter of 2025. Total production before royalties for the fourth quarter of 2025 of 1,658,681 BOE/d increased 13% from 1,470,428 BOE/d for the fourth quarter of 2024 and was comparable with 1,620,261 BOE/d for the third quarter of 2025. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production, before royalties' section of this MD&A.

Product Prices

In the Company's Exploration and Production segments, realized crude oil and NGLs prices averaged $64.42 per bbl for the fourth quarter of 2025, a decrease of 14% from $75.22 per bbl for the fourth quarter of 2024 and a decrease of 11% from $72.57 per bbl for the third quarter of 2025. The realized natural gas price increased 43% to average $2.89 per Mcf for the fourth quarter of 2025 from $2.02 per Mcf for the fourth quarter of 2024 and increased 94% from $1.49 per Mcf for the third quarter of 2025. In the Oil Sands Mining and Upgrading segment, the Company's realized SCO sales price decreased 20% to average $75.90 per bbl for the fourth quarter of 2025 from $95.08 per bbl for the fourth quarter of 2024 and decreased 14% from $87.85 per bbl for the third quarter of 2025. The Company's realized product pricing is reflective of the prevailing benchmark pricing. Crude oil and NGLs and natural gas prices are discussed in detail in the 'Business Environment', 'Realized Product Prices – Exploration and Production', and the 'Realized Product Prices, Royalties and Transportation – 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 $14.35 per bbl for the fourth quarter of 2025, an increase of 9% from $13.15 per bbl for the fourth quarter of 2024 and $13.18 per bbl for the third quarter of 2025. Natural gas production expense[(1)] averaged $1.10 per Mcf for the fourth quarter of 2025, comparable with $1.12 per Mcf for the fourth quarter of 2024 and a decrease of 5% from $1.16 per Mcf for the third quarter of 2025. In the Oil Sands Mining and Upgrading segment, production expense[(1)] averaged $21.84 per bbl for the fourth quarter of 2025, an increase of 4% from $20.97 per bbl for the fourth quarter of 2024 and an increase of 3% from $21.29 per bbl for the third quarter of 2025. Crude oil and NGLs and natural gas production expense is discussed in detail in the 'Production Expense – Exploration and Production' and the 'Production Expense – Oil Sands Mining and Upgrading' sections of this MD&A.

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

SUMMARY OF QUARTERLY FINANCIAL RESULTS

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

($ millions, except per common share amounts)	**Dec 31 2025**	Sep 30 2025	Jun 30 2025	Mar 31 2025
Product sales [(1)]	**$ 10,710**	$ 11,070	$ 9,675	$ 12,712
Crude oil and NGLs	**$ 9,666**	$ 10,468	$ 8,874	$ 11,732
Natural gas	**$ 735**	$ 399	$ 600	$ 716
Net earnings	**$ 5,303**	$ 600	$ 2,459	$ 2,458
Net earnings per common share				
– basic	**$ 2.55**	$ 0.29	$ 1.17	$ 1.17
– diluted	**$ 2.54**	$ 0.29	$ 1.17	$ 1.17

($ 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				
– basic	$ 0.54	$ 1.07	$ 0.80	$ 0.46
– diluted	$ 0.54	$ 1.06	$ 0.80	$ 0.46

(1) Further details related to product sales for the three months ended December 31, 2025 and 2024 are disclosed in note 16 to the financial statements.

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

- **Crude oil pricing** – Fluctuations in global supply/demand including crude oil production levels from OPEC+ and its impact on world supply, the impact of geopolitical and market uncertainties (including those due to the conflicts in the Middle East, Ukraine and Venezuela, and the impacts of ongoing tariff and trade uncertainty) 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, the impact of liquefied natural gas ("LNG") demand and exports, 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 declines, the impact of turnarounds in the Oil Sands Mining and Upgrading segment, the impact and timing of acquisitions (including the acquisition of working interests in AOSP and Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, the acquisition of assets in the Grande Prairie area in the third quarter of 2025, and the AOSP asset swap in the fourth quarter of 2025), wildfires, and maintenance activities in the North America Exploration and Production segment. Sales volumes in the International segments also reflected fluctuations due to the timing of liftings, planned abandonment activities in the North Sea, and temporary suspension of production at Baobab in Offshore Africa for planned floating production storage and offloading vessel ("FPSO") maintenance.
- **Natural gas sales volumes** – Fluctuations in production due to the Company's drilling program in the North America Exploration and Production segment, the impact and timing of acquisitions (including the acquisition of a working interest in the Duvernay assets in the fourth quarter of 2024, the acquisition of assets in the Palliser Block in the second quarter of 2025, and the acquisition of assets in the Grande Prairie area in the third quarter of 2025), natural field declines, the impact of seasonal conditions, and wildfires 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, carbon tax, fluctuating energy costs, inflationary cost pressures, cost optimizations across all segments, turnarounds 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 in the Oil Sands Mining and Upgrading segment, and recoverability charges related to the North Sea and Offshore 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 lease liabilities, the impact of movements in benchmark interest rates on outstanding floating rate long-term debt, and interest on PRT and corporate tax 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 and working capital.
- **Gain on acquisitions, disposition, and remeasurement** – A gain on acquisitions representing the excess of the fair value of the net assets acquired compared to total purchase consideration and previously held interests, a gain on remeasurement to fair value of the Company's pre-existing 90% interest in the AOSP mines as part of the AOSP asset swap, and a gain on disposition of the 10% interest in Scotford and Quest disposed of as part of the AOSP asset swap.

BUSINESS ENVIRONMENT

Global crude oil benchmark pricing declined through the fourth quarter of 2025 as increasing global supply outpaced relatively modest demand growth, which remained subdued amid ongoing tariff and trade uncertainty. Late in the fourth quarter of 2025, escalating geopolitical tensions contributed to heightened concerns regarding potential crude oil supply disruptions entering into 2026. Natural gas benchmark pricing increased during the fourth quarter of 2025, driven by seasonal demand factors and continued strength in LNG export activity out of the US Gulf Coast. In Canada, AECO benchmark pricing improved due to robust export volumes out of the Western Canadian Sedimentary Basin ("WCSB"). The ongoing ramp-up of LNG Canada is expected to further increase LNG demand and support AECO pricing in 2026.

In the first quarter of 2025, the US government announced tariffs on certain Canadian goods. While these actions have contributed to market volatility, including commodity price and foreign currency volatility, these tariffs have not had a material impact on the Company's financial results as of the date of this MD&A. The duration of these trade actions remains uncertain, and broader changes to US economic policy may have a material effect on the Company's business, financial conditions, or results in future periods. The Company will continue to monitor and assess the implications of any current or emerging US economic policies.

Benchmark Commodity Prices

(Average for the period)	Three Months Ended **Dec 31 2025**	Three Months Ended Sep 30 2025	Three Months Ended Dec 31 2024	Year Ended **Dec 31 2025**	Year Ended Dec 31 2024
WTI benchmark price (US$/bbl)	**$ 59.13**	$ 64.95	$ 70.27	**$ 64.77**	$ 75.72
Dated Brent benchmark price (US$/bbl)	**$ 63.69**	$ 69.08	$ 74.69	**$ 69.02**	$ 80.75
WCS Heavy Differential from WTI (US$/bbl)	**$ 11.20**	$ 10.36	$ 12.55	**$ 11.10**	$ 14.73
SCO price (US$/bbl)	**$ 57.78**	$ 66.26	$ 71.13	**$ 64.42**	$ 75.09
Condensate benchmark price (US$/bbl)	**$ 57.01**	$ 63.12	$ 70.66	**$ 63.32**	$ 72.94
NYMEX benchmark price (US$/MMBtu)	**$ 3.55**	$ 3.07	$ 2.79	**$ 3.43**	$ 2.27
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 0.94	$ 1.38	**$ 1.76**	$ 1.36
US/Canadian dollar average exchange rate (US$)	**$ 0.7170**	$ 0.7262	$ 0.7151	**$ 0.7155**	$ 0.7300

Substantially all of the Company's production is sold based on US dollar benchmark pricing, with crude oil marketed based on WTI and Brent indices, and natural gas marketed using a diversified mix of AECO- and NYMEX-based pricing. 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$64.77 per bbl for the year ended December 31, 2025, a decrease of 14% from US$75.72 per bbl for the year ended December 31, 2024. WTI averaged US$59.13 per bbl for the fourth quarter of 2025, a decrease of 16% from US$70.27 per bbl for the fourth quarter of 2024 and a decrease of 9% from US$64.95 per bbl for the third quarter of 2025.

Crude oil sales contracts for the Company's International segments are typically based on Brent benchmark pricing, which is representative of international markets and overall global supply and demand. Brent averaged US$69.02 per bbl for the year ended December 31, 2025, a decrease of 15% from US$80.75 per bbl for the year ended December 31, 2024. Brent averaged US$63.69 per bbl for the fourth quarter of 2025, a decrease of 15% from US$74.69 per bbl for the fourth quarter of 2024 and a decrease of 8% from US$69.08 per bbl for the third quarter of 2025.

The decrease in WTI and Brent benchmark pricing for the three months and year ended December 31, 2025 from the comparable periods primarily reflected increased global supply and inventory builds driven by near-record production from non-OPEC+ producers and higher OPEC+ output. Supply gains exceeded global demand growth, which remained muted amid ongoing tariff and trade uncertainty.

The WCS Heavy Differential averaged US$11.10 per bbl for the year ended December 31, 2025, compared with US$14.73 per bbl for the year ended December 31, 2024. The WCS Heavy Differential averaged US$11.20 per bbl for the fourth quarter of 2025, compared with US$12.55 per bbl for the fourth quarter of 2024 and US$10.36 per bbl for the third quarter of 2025. The narrowing of the WCS Heavy Differential for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected full year takeaway capacity on the TMX pipeline and strong US Gulf Coast heavy oil pricing. The widening of the WCS Heavy Differential for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected seasonal demand factors and strong production, together with pipeline apportionment in the WCSB.

The SCO price averaged US$64.42 per bbl for the year ended December 31, 2025, a decrease of 14% from US$75.09 per bbl for the year ended December 31, 2024. The SCO price averaged US$57.78 per bbl for the fourth quarter of 2025, a decrease of 19% from US$71.13 per bbl for the fourth quarter of 2024 and a decrease of 13% from US$66.26 per bbl for the third quarter of 2025. The decrease in SCO pricing for the three months and year ended December 31, 2025 from the comparable periods primarily reflected weaker WTI benchmark pricing.

NYMEX benchmark pricing averaged US$3.43 per MMBtu for the year ended December 31, 2025, an increase of 51% from US$2.27 per MMBtu for the year ended December 31, 2024. NYMEX benchmark pricing averaged US$3.55 per MMBtu for the fourth quarter of 2025, an increase of 27% from US$2.79 per MMBtu for the fourth quarter of 2024 and an increase of 16% from US$3.07 per MMBtu for the third quarter of 2025. The increase in NYMEX natural gas pricing for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected lower US inventory levels in the first half of 2025, combined with record LNG exports out of the US Gulf Coast. The increase in NYMEX natural gas pricing for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected seasonal demand factors and strong LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged $1.76 per GJ for the year ended December 31, 2025, an increase of 29% from $1.36 per GJ for the year ended December 31, 2024. AECO benchmark pricing averaged $2.22 per GJ for the fourth quarter of 2025, an increase of 61% from $1.38 per GJ for the fourth quarter of 2024 and an increase of 136% from $0.94 per GJ for the third quarter of 2025. The increase in AECO natural gas pricing for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected higher NYMEX benchmark pricing and increased exports out of the WCSB. The increase in AECO natural gas pricing for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected improved seasonal demand factors and stronger WCSB exports following third quarter pipeline maintenance.

DAILY PRODUCTION, before royalties

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**585,497**	584,625	531,960	**569,401**	509,288
North America – Oil Sands Mining and Upgrading (1)	**619,901**	581,136	534,631	**565,102**	472,245
International – Exploration and Production					
North Sea	**7,618**	7,045	11,467	**8,468**	11,536
Offshore Africa	**2,348**	2,798	11,944	**3,204**	12,534
Total International (2)	**9,966**	9,843	23,411	**11,672**	24,070
Total Crude oil and NGLs	**1,215,364**	1,175,604	1,090,002	**1,146,175**	1,005,603
Natural gas (MMcf/d) (3)					
North America	**2,657**	2,658	2,273	**2,538**	2,136
International					
North Sea	**3**	2	4	**3**	2
Offshore Africa	**—**	8	6	**6**	9
Total International	**3**	10	10	**9**	11
Total Natural gas	**2,660**	2,668	2,283	**2,547**	2,147
Total Barrels of oil equivalent (BOE/d)	**1,658,681**	1,620,261	1,470,428	**1,570,757**	1,363,496
Product mix					
Light and medium crude oil and NGLs	**12%**	12%	10%	**11%**	10%
Pelican Lake heavy crude oil	**3%**	3%	3%	**3%**	3%
Primary heavy crude oil	**5%**	5%	6%	**6%**	6%
Thermal bitumen	**16%**	17%	19%	**17%**	20%
Synthetic crude oil (1)	**37%**	36%	36%	**36%**	35%
Natural gas	**27%**	27%	26%	**27%**	26%
Percentage of product sales (1) (4) (5)					
Crude oil and NGLs	**92%**	96%	96%	**94%**	96%
Natural gas	**8%**	4%	4%	**6%**	4%

(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 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America – Exploration and Production	**499,585**	479,660	425,682	**476,850**	408,237
North America – Oil Sands Mining and Upgrading [(1)]	**518,709**	473,188	432,701	**467,415**	386,171
International – Exploration and Production					
North Sea	**7,610**	7,017	11,441	**8,451**	11,509
Offshore Africa	**2,240**	2,669	11,364	**3,061**	11,918
Total International	**9,850**	9,686	22,805	**11,512**	23,427
Total Crude oil and NGLs	**1,028,144**	962,534	881,188	**955,777**	817,835
Natural gas (MMcf/d)					
North America	**2,570**	2,615	2,223	**2,466**	2,091
International					
North Sea	**3**	2	4	**3**	2
Offshore Africa	**—**	8	6	**6**	9
Total International	**3**	10	10	**9**	11
Total Natural gas	**2,573**	2,625	2,233	**2,475**	2,102
Total Barrels of oil equivalent (BOE/d)	**1,456,944**	1,399,968	1,253,347	**1,368,198**	1,168,209

(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, thermal bitumen, SCO, and natural gas.

Record crude oil and NGLs production before royalties for the year ended December 31, 2025 averaged 1,146,175 bbl/d, an increase of 14% from 1,005,603 bbl/d for the year ended December 31, 2024. Record crude oil and NGLs production before royalties for the fourth quarter of 2025 averaged 1,215,364 bbl/d, an increase of 12% from 1,090,002 bbl/d for the fourth quarter of 2024 and an increase of 3% from 1,175,604 bbl/d for the third quarter of 2025. The increase in crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, strong utilization in the Oil Sands Mining and Upgrading segment, and strong drilling results in the North America Exploration and Production segment. The increase for the fourth quarter of 2025 from the fourth quarter of 2024 also reflected the completion of the AOSP asset swap in November 2025. The increase in crude oil and NGLs production before royalties for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the completion of the AOSP asset swap in November 2025, combined with strong utilization in the Oil Sands Mining and Upgrading segment.

Annual crude oil and NGLs production before royalties for 2025 was within the Company's previously issued production target of 1,137,000 bbl/d and 1,151,000 bbl/d. Annual crude oil and NGLs production before royalties for 2026 is now targeted to average between 1,188,000 bbl/d and 1,229,000 bbl/d. Production targets constitute forward-looking statements. Refer to the 'Advisory' section of this MD&A for further details on forward-looking statements.

Record natural gas production before royalties for the year ended December 31, 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d for the year ended December 31, 2024. Natural gas production before royalties for the fourth quarter of 2025 averaged 2,660 MMcf/d, an increase of 17% from 2,283 MMcf/d for the fourth quarter of 2024 and comparable with 2,668 MMcf/d for the third quarter of 2025. The increase in natural gas production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

Annual natural gas production before royalties for 2025 was within the Company's previously issued production target of 2,535 MMcf/d and 2,575 MMcf/d. Annual natural gas production before royalties for 2026 is now targeted to average between 2,560 MMcf/d and 2,615 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, 2025 averaged 569,401 bbl/d, an increase of 12% from 509,288 bbl/d for the year ended December 31, 2024. North America crude oil and NGLs production before royalties for the fourth quarter of 2025 of 585,497 bbl/d increased 10% from 531,960 bbl/d for the fourth quarter of 2024 and was comparable with 584,625 bbl/d for the third quarter of 2025. The increase in North America crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results.

The Company's thermal in situ assets continued to demonstrate long life low decline production before royalties, averaging 266,308 bbl/d for the fourth quarter of 2025, a decrease of 4% from 276,231 bbl/d for the fourth quarter of 2024 and comparable with 274,752 bbl/d for the third quarter of 2025. The decrease in thermal in situ production for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected the cyclical nature of Primrose and natural field declines, partially offset by thermal pad additions.

Pelican Lake heavy crude oil production before royalties for the fourth quarter of 2025 averaged 41,577 bbl/d, a decrease of 6% from 44,035 bbl/d for the fourth quarter of 2024 reflecting Pelican Lake's long life low decline production, and comparable with 42,070 bbl/d for the third quarter of 2025.

Record North America natural gas production before royalties for the year ended December 31, 2025 averaged 2,538 MMcf/d, an increase of 19% from 2,136 MMcf/d for the year ended December 31, 2024. Natural gas production before royalties averaged 2,657 MMcf/d for the fourth quarter of 2025, an increase of 17% from 2,273 MMcf/d for the fourth quarter of 2024 and comparable with 2,658 MMcf/d for the third quarter of 2025. The increase in natural gas production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results in the Company's liquids-rich natural gas assets.

North America – Oil Sands Mining and Upgrading

Record SCO production before royalties for the year ended December 31, 2025 averaged 565,102 bbl/d, an increase of 20% from 472,245 bbl/d for the year ended December 31, 2024. Record SCO production before royalties for the fourth quarter of 2025 averaged 619,901 bbl/d, an increase of 16% from 534,631 bbl/d for the fourth quarter of 2024 and an increase of 7% from 581,136 bbl/d for the third quarter of 2025. The increase in SCO production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the acquisition completed in December 2024, combined with strong utilization. The increase in SCO production for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the completion of the AOSP asset swap in November 2025, combined with strong utilization.

International – Exploration and Production

International crude oil and NGLs production before royalties for the year ended December 31, 2025 averaged 11,672 bbl/d, a decrease of 52% from 24,070 bbl/d for the year ended December 31, 2024. International crude oil and NGLs production before royalties for the fourth quarter of 2025 averaged 9,966 bbl/d, a decrease of 57% from 23,411 bbl/d for the fourth quarter of 2024 and comparable with 9,843 bbl/d for the third quarter of 2025. The decrease in International crude oil and NGLs production before royalties for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected the temporary suspension of production at Baobab in Offshore Africa due to planned maintenance on its FPSO, which is expected to return to service in the second quarter of 2026, planned North Sea abandonments conducted as part of the previously announced decommissioning plans, and natural field declines.

OPERATING HIGHLIGHTS – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) (1)					
Realized price (2)	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
Transportation (3)	**7.14**	6.93	6.08	**7.02**	5.50
Realized price, net of transportation (2)	**57.28**	65.64	69.14	**64.52**	72.26
Royalties (4)	**9.46**	13.10	14.77	**11.53**	14.85
Production expense (5)	**14.35**	13.18	13.15	**14.33**	14.72
Netback (2)	**$ 33.47**	$ 39.36	$ 41.22	**$ 38.66**	$ 42.69
Natural gas ($/Mcf) (1)					
Realized price (6)	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86
Transportation (3)	**0.56**	0.57	0.59	**0.59**	0.62
Realized price, net of transportation	**2.33**	0.92	1.43	**1.92**	1.24
Royalties (4)	**0.09**	0.02	0.04	**0.08**	0.05
Production expense (5)	**1.10**	1.16	1.12	**1.14**	1.22
Netback (7)	**$ 1.14**	$ (0.26)	$ 0.27	**$ 0.70**	$ (0.03)
Barrels of oil equivalent ($/BOE) (1)					
Realized price (2)	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82
Transportation (3)	**5.56**	5.38	5.06	**5.54**	4.78
Realized price, net of transportation (2)	**39.29**	39.93	44.48	**42.44**	46.04
Royalties (4)	**5.73**	7.53	8.85	**6.90**	8.96
Production expense (5)	**11.08**	10.50	10.53	**11.18**	11.73
Netback (2)	**$ 22.48**	$ 21.90	$ 25.10	**$ 24.36**	$ 25.35

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

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

(3) Calculated as transportation expense divided by respective sales volumes.

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

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

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

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

REALIZED PRODUCT PRICES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) [1]					
North America [2]	**$ 63.83**	$ 72.35	$ 74.46	**$ 70.90**	$ 76.37
International average [3]	**$ 87.45**	$ 94.08	$ 96.36	**$ 98.07**	$ 108.80
North Sea [3]	**$ 89.02**	$ 90.19	$ 103.80	**$ 97.26**	$ 111.53
Offshore Africa [3]	**$ 83.53**	$ 99.90	$ 86.93	**$ 99.71**	$ 106.00
Crude oil and NGLs average [2]	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
Natural gas ($/Mcf) [1] [3]					
North America	**$ 2.89**	$ 1.45	$ 1.98	**$ 2.47**	$ 1.81
International average	**$ 8.87**	$ 11.22	$ 11.28	**$ 12.45**	$ 12.01
North Sea	**$ 8.87**	$ 8.57	$ 8.87	**$ 11.77**	$ 9.93
Offshore Africa	**$ —**	$ 11.87	$ 12.62	**$ 12.77**	$ 12.46
Natural gas average	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86
Average ($/BOE) [1] [2]	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82

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

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

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

North America

North America realized crude oil and NGLs prices decreased 7% to average $70.90 per bbl for the year ended December 31, 2025 from $76.37 per bbl for the year ended December 31, 2024. North America realized crude oil and NGLs prices averaged $63.83 per bbl for the fourth quarter of 2025, a decrease of 14% from $74.46 per bbl for the fourth quarter of 2024 and a decrease of 12% from $72.35 per bbl for the third quarter of 2025. The decrease in North America realized crude oil and NGLs prices per bbl for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected lower WTI benchmark pricing, partially offset by a narrowing of the WCS Heavy Differential. The decrease in North America realized crude oil and NGLs prices per bbl for the fourth quarter of 2025 from the comparable periods primarily reflected lower WTI benchmark pricing. Realized crude oil and NGLs pricing is also directly impacted by fluctuations in foreign exchange rates as sales prices are primarily denominated with reference to US dollar benchmarks. The Company continues to focus on its crude oil blending and marketing strategy and in the fourth quarter of 2025 contributed approximately 230,000 bbl/d of heavy crude oil blends to the WCS stream.

North America realized natural gas prices increased 36% to average $2.47 per Mcf for the year ended December 31, 2025 from $1.81 per Mcf for the year ended December 31, 2024. North America realized natural gas prices increased 46% to average $2.89 per Mcf for the fourth quarter of 2025 from $1.98 per Mcf for the fourth quarter of 2024 and increased 99% from $1.45 per Mcf for the third quarter of 2025. The increase in North America realized natural gas prices per Mcf for the three months and year ended December 31, 2025 from the comparable periods primarily reflected higher AECO benchmark and export pricing.

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

	Three Months Ended		
(Quarterly average)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Wellhead Price [1]			
Light and medium crude oil and NGLs ($/bbl)	**$ 58.26**	$ 66.29	$ 68.63
Pelican Lake heavy crude oil ($/bbl)	**$ 66.75**	$ 75.94	$ 79.88
Primary heavy crude oil ($/bbl)	**$ 65.69**	$ 75.55	$ 78.34
Thermal bitumen ($/bbl)	**$ 66.61**	$ 74.83	$ 75.11
Natural gas ($/Mcf)	**$ 2.89**	$ 1.45	$ 1.98

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

International

International realized crude oil and NGLs prices decreased 10% to average $98.07 per bbl for the year ended December 31, 2025 from $108.80 per bbl for the year ended December 31, 2024. International realized crude oil and NGLs prices decreased 9% to average $87.45 per bbl for the fourth quarter of 2025 from $96.36 per bbl for the fourth quarter of 2024 and decreased 7% from $94.08 per bbl for the third quarter of 2025. 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, prevailing Brent benchmark prices and foreign exchange rates at the time of lifting.

ROYALTIES – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 9.67**	$ 13.21	$ 15.22	**$ 11.77**	$ 15.40
International average	**$ 1.16**	$ 2.05	$ 1.99	**$ 1.56**	$ 2.75
North Sea	**$ 0.09**	$ 0.35	$ 0.23	**$ 0.15**	$ 0.26
Offshore Africa	**$ 3.84**	$ 4.60	$ 4.22	**$ 4.41**	$ 5.30
Crude oil and NGLs average	**$ 9.46**	$ 13.10	$ 14.77	**$ 11.53**	$ 14.85
Natural gas ($/Mcf) (1)					
North America	**$ 0.09**	$ 0.02	$ 0.04	**$ 0.08**	$ 0.04
Offshore Africa	**$ —**	$ 0.55	$ 0.58	**$ 0.59**	$ 0.57
Natural gas average	**$ 0.09**	$ 0.02	$ 0.04	**$ 0.08**	$ 0.05
Average ($/BOE) (1)	**$ 5.73**	$ 7.53	$ 8.85	**$ 6.90**	$ 8.96

(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, 2025 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates[(1)] averaged approximately 17% of product sales for the year ended December 31, 2025 compared with 20% of product sales for the year ended December 31, 2024. Crude oil and NGLs royalty rates averaged approximately 15% of product sales for the fourth quarter of 2025 compared with 20% for the fourth quarter of 2024 and 18% for the third quarter of 2025. The decrease in royalty rates for the three months and year ended December 31, 2025 from the comparable periods primarily reflected lower benchmark pricing and the impact of sliding scale royalty rates.

Natural gas royalty rates averaged approximately 3% of product sales for the year ended December 31, 2025 compared with 2% of product sales for the year ended December 31, 2024. Natural gas royalty rates averaged approximately 3% of product sales for the fourth quarter of 2025 compared with 2% for the fourth quarter of 2024 and the third quarter of 2025. The increase in royalty rates for the three months and year ended December 31, 2025 from the comparable periods primarily reflected higher 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 4% for the year ended December 31, 2025 compared with 5% of product sales for the year ended December 31, 2024. Royalty rates as a percentage of product sales averaged approximately 5% for the fourth quarter of 2025 compared with 5% of product sales for the fourth quarter of 2024 and the third quarter of 2025. Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

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

PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs ($/bbl) (1)					
North America	**$ 12.24**	$ 11.97	$ 10.83	**$ 12.19**	$ 12.55
International average	**$ 96.90**	$ 134.12	$ 77.66	**$ 103.48**	$ 62.99
North Sea	**$ 115.45**	$ 188.98	$ 118.91	**$ 136.47**	$ 103.28
Offshore Africa	**$ 50.50**	$ 52.17	$ 25.34	**$ 36.73**	$ 21.77
Crude oil and NGLs average	**$ 14.35**	$ 13.18	$ 13.15	**$ 14.33**	$ 14.72
Natural gas ($/Mcf) (1)					
North America	**$ 1.09**	$ 1.14	$ 1.09	**$ 1.11**	$ 1.19
International average	**$ 11.69**	$ 8.18	$ 7.81	**$ 9.23**	$ 6.51
North Sea	**$ 11.69**	$ 15.64	$ 9.38	**$ 12.18**	$ 8.95
Offshore Africa	**$ —**	$ 6.32	$ 6.94	**$ 7.80**	$ 5.98
Natural gas average	**$ 1.10**	$ 1.16	$ 1.12	**$ 1.14**	$ 1.22
Average ($/BOE) (1)	**$ 11.08**	$ 10.50	$ 10.53	**$ 11.18**	$ 11.73

(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, 2025 averaged $12.19 per bbl, comparable with $12.55 per bbl for the year ended December 31, 2024. North America crude oil and NGLs production expense for the fourth quarter of 2025 of $12.24 per bbl increased 13% from $10.83 per bbl for the fourth quarter of 2024 and was comparable with $11.97 per bbl for the third quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected higher fuel costs.

North America natural gas production expense for the year ended December 31, 2025 averaged $1.11 per Mcf, a decrease of 7% from $1.19 per Mcf for the year ended December 31, 2024. North America natural gas production expense for the fourth quarter of 2025 of $1.09 per Mcf was comparable with $1.09 per Mcf for the fourth quarter of 2024 and decreased 4% from $1.14 per Mcf for the third quarter of 2025. The decrease in natural gas production expense per Mcf for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher production volumes. The decrease in natural gas production expense per Mcf for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected lower service costs.

International

International crude oil and NGLs production expense for the year ended December 31, 2025 averaged $103.48 per bbl, an increase of 64% from $62.99 per bbl for the year ended December 31, 2024. International crude oil and NGLs production expense for the fourth quarter of 2025 of $96.90 per bbl increased 25% from $77.66 per bbl for the fourth quarter of 2024 and decreased 28% from $134.12 per bbl for the third quarter of 2025. The increase in crude oil and NGLs production expense per bbl for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected activities at Ninian in the pre-cessation period, the timing of liftings from various fields that have different cost structures, and the impact of foreign exchange. The decrease in crude oil and NGLs production expense per bbl for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the timing of liftings from various fields that have different cost structures.

ADJUSTED DEPLETION, DEPRECIATION AND AMORTIZATION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
North America	**$ 1,217**	$ 1,188	$ 1,010	**$ 4,582**	$ 3,831
North Sea	**215**	1,285	221	**1,573**	279
Offshore Africa	**340**	20	46	**432**	297
Depletion, depreciation and amortization	**$ 1,772**	$ 2,493	$ 1,277	**$ 6,587**	$ 4,407
Less: Recoverability charges (1)	**519**	1,258	160	**1,777**	222
Adjusted depletion, depreciation and amortization (2)	**$ 1,253**	$ 1,235	$ 1,117	**$ 4,810**	$ 4,185
$/BOE (3)	**$ 12.98**	$ 13.08	$ 13.01	**$ 13.07**	$ 12.92

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

(2) This is a non-GAAP financial measure used to calculate depletion, depreciation and amortization, less the impact of charges that are not related to current period normal course depletion, depreciation and amortization expense such as asset recoverability charges that are not related to current period production. It may not be comparable to similar measures presented by other companies and should not be considered an alternative to, or more meaningful than, the most directly comparable financial measure presented in the financial statements (depletion, depreciation and amortization expense), as an indication of the Company's performance.

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

Adjusted depletion, depreciation and amortization expense for the year ended December 31, 2025 averaged $13.07 per BOE, comparable with $12.92 per BOE for the year ended December 31, 2024. Adjusted depletion, depreciation and amortization expense for the fourth quarter of 2025 averaged $12.98 per BOE, comparable with $13.01 per BOE for the fourth quarter of 2024 and $13.08 per BOE for the third quarter of 2025.

International Matters – North Sea and Offshore Africa

Pre-tax recoverability charges of $1,777 million in 2025 reflect the acceleration of the Company's abandonment and decommissioning activities and revisions to cost estimates in the North Sea, together with strategic decisions to not pursue an extension of its Production Sharing Contract ("PSC") for the Espoir Field, Block CI-26, in Offshore Africa and to not pursue development of Kossipo in Offshore Africa.

In the North Sea, following a competitive tender for the Ninian South Platform, estimated abandonment and decommissioning costs were higher than originally budgeted. Accordingly, in the third quarter of 2025, the Company updated its cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni and Thelma fields). Additionally, in the third quarter of 2025, based on current and forecasted economic conditions, including commodity prices and market egress, the Company determined that the T-Block assets were no longer economically viable. As a result, at September 30, 2025, the Company recognized a non-cash charge of $695 million, comprised of a $734 million recoverability charge related to Ninian abandonment costs and a $524 million recoverability charge related to T-Block, net of deferred tax recoveries of $359 million and $204 million, respectively.

Further, during the fourth quarter of 2025, the Company decided to accelerate cessation of production at T-Block to the first quarter of 2027 and de-book associated reserves. This resulted in an additional non-cash charge of $141 million, primarily reflecting revised timing of the abandonment activities and updates to cost estimates, and comprised of a recoverability charge of $204 million, net of deferred tax recoveries of $63 million.

In Offshore Africa, during the fourth quarter of 2025, the Company determined that it would not pursue an extension of its PSC for the Espoir Field, Block CI-26, and de-booked associated crude oil reserves. The Company is working with the Government of Côte d'Ivoire to facilitate the transition of operatorship in the second half of 2026. As a result, the Company recognized a non-cash recoverability charge of $269 million as at December 31, 2025. Additionally, the Company decided not to pursue development of Kossipo in Offshore Africa, and recognized a recoverability charge of $46 million related to the derecognition of its exploration and evaluation assets.

Estimates of asset retirement obligations and related tax recoveries remain subject to revision as abandonment activities progress. Recoverability charges are recognized in depletion, depreciation and amortization expense.

ASSET RETIREMENT OBLIGATION ACCRETION – EXPLORATION AND PRODUCTION

	Three Months Ended			Year Ended	
($ millions, except per BOE amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
North America	**$ 58**	$ 57	$ 58	**$ 221**	$ 231
North Sea	**23**	13	17	**64**	65
Offshore Africa	**2**	3	3	**9**	9
Asset retirement obligation accretion	**$ 83**	$ 73	$ 78	**$ 294**	$ 305
$/BOE (1)	**$ 0.85**	$ 0.77	$ 0.89	**$ 0.80**	$ 0.94

(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, 2025 averaged $0.80 per BOE, a decrease of 15% from $0.94 per BOE for the year ended December 31, 2024. Asset retirement obligation accretion expense for the fourth quarter of 2025 averaged $0.85 per BOE, a decrease of 4% from $0.89 per BOE for the fourth quarter of 2024 and an increase of 10% from $0.77 per BOE for the third quarter of 2025. The decrease in asset retirement obligation accretion expense per BOE for the three months and year ended December 31, 2025 from the comparable periods in 2024 reflected the impact of changes in discount rates at December 31, 2024, combined with higher sales volumes in 2025, partially offset by revisions in cost and timing estimates at December 31, 2024, North America acquisitions completed during 2025, and North Sea cost and timing estimate revisions during 2025. The increase in asset retirement obligation accretion expense per BOE for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the impact of revisions to cost and timing estimates at September 30, 2025 associated with the North Sea abandonment activities.

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. Record SCO production averaged 619,901 bbl/d in the fourth quarter of 2025 primarily reflecting strong utilization in the Oil Sands Mining and Upgrading segment. The completion of the AOSP asset swap also contributed to increased volumes in the fourth quarter of 2025.

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

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Realized SCO sales price (1)	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03
Bitumen value for royalty purposes (2)	**$ 58.68**	$ 68.06	$ 69.35	**$ 66.23**	$ 72.68
Bitumen royalties (3)	**$ 9.54**	$ 15.80	$ 17.20	**$ 13.84**	$ 17.23
Transportation (4)	**$ 2.56**	$ 3.86	$ 3.60	**$ 3.31**	$ 2.91

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

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

(3) Calculated as royalties divided by sales volumes.

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

The realized SCO sales price averaged $86.41 per bbl for the year ended December 31, 2025, a decrease of 12% from $98.03 per bbl for the year ended December 31, 2024. The realized SCO sales price averaged $75.90 per bbl for the fourth quarter of 2025, a decrease of 20% from $95.08 per bbl for the fourth quarter of 2024 and a decrease of 14% from $87.85 per bbl for the third quarter of 2025. The decrease in realized SCO sales price per bbl for the three months and year ended December 31, 2025 from the comparable periods primarily reflected lower WTI benchmark pricing.

The fluctuations in bitumen royalties per bbl in any particular period reflect prevailing bitumen value for royalty purposes, and the impact of sliding scale royalty rates. The decrease in bitumen royalties per bbl for the three months and year ended December 31, 2025 from the comparable periods primarily reflected the decrease in average bitumen value for royalty purposes and the impact of royalty true-ups.

Transportation expense averaged $3.31 per bbl for the year ended December 31, 2025, an increase of 14% from $2.91 per bbl for the year ended December 31, 2024. Transportation expense averaged $2.56 per bbl for the fourth quarter of 2025, a decrease of 29% from $3.60 per bbl for the fourth quarter of 2024 and a decrease of 34% from $3.86 per bbl for the third quarter of 2025. The increase in transportation expense per bbl for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025. The decrease in transportation expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected lower volumes shipped to the US Gulf Coast, partially offset by higher volumes shipped on the TMX pipeline. The decrease for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected lower volumes shipped to the US Gulf Coast and on the TMX pipeline, as well as a reduction of transportation expense following the recognition of the Corridor pipeline as a leased asset in the fourth quarter.

PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Production expense, excluding natural gas costs	**$ 1,207**	$ 1,116	$ 991	**$ 4,543**	$ 3,801
Natural gas costs	**46**	19	28	**150**	120
Production expense	**$ 1,253**	$ 1,135	$ 1,019	**$ 4,693**	$ 3,921

	Three Months Ended			Year Ended	
($/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Production expense, excluding natural gas costs (1)	**$ 21.03**	$ 20.93	$ 20.39	**$ 21.94**	$ 22.18
Natural gas costs (2)	**0.81**	0.36	0.58	**0.72**	0.70
Production expense (3)	**$ 21.84**	$ 21.29	$ 20.97	**$ 22.66**	$ 22.88
Sales volumes (bbl/d)	**624,125**	579,209	528,248	**567,335**	468,280

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

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

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

Production expense for the year ended December 31, 2025 averaged $22.66 per bbl, comparable with $22.88 per bbl for the year ended December 31, 2024. Production expense for the fourth quarter of 2025 averaged $21.84 per bbl, an increase of 4% from $20.97 per bbl for the fourth quarter of 2024 and an increase of 3% from $21.29 per bbl for the third quarter of 2025. The increase in production expense per bbl for the fourth quarter of 2025 from the comparable periods primarily reflected higher energy costs.

DEPLETION, DEPRECIATION AND AMORTIZATION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Depletion, depreciation and amortization	**$ 762**	$ 713	$ 621	**$ 2,780**	$ 2,258
$/bbl (1)	**$ 13.26**	$ 13.38	$ 12.76	**$ 13.42**	$ 13.17

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

Depletion, depreciation and amortization expense for the year ended December 31, 2025 averaged $13.42 per bbl, comparable with $13.17 per bbl for the year ended December 31, 2024. Depletion, depreciation and amortization expense for the fourth quarter of 2025 of $13.26 per bbl increased 4% from $12.76 per bbl for the fourth quarter of 2024 and was comparable with $13.38 per bbl for the third quarter of 2025. The increase in depletion, depreciation and amortization expense per bbl for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected a higher depletable base due to the remeasurement of the AOSP mines and the recognition of the Corridor pipeline as a leased asset following the AOSP asset swap.

ASSET RETIREMENT OBLIGATION ACCRETION – OIL SANDS MINING AND UPGRADING

	Three Months Ended			Year Ended	
($ millions, except per bbl amounts)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Asset retirement obligation accretion	**$ 21**	$ 22	$ 20	**$ 86**	$ 84
$/bbl (1)	**$ 0.37**	$ 0.40	$ 0.44	**$ 0.42**	$ 0.49

(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, 2025 of $0.42 per bbl decreased 14% from $0.49 per bbl for the year ended December 31, 2024. Asset retirement obligation accretion expense for the fourth quarter of 2025 of $0.37 per bbl decreased 16% from $0.44 per bbl for the fourth quarter of 2024 and decreased 8% from $0.40 per bbl for the third quarter of 2025. The decrease in asset retirement obligation accretion expense per bbl for the three months and year ended December 31, 2025 from the comparable periods primarily reflected the impact of higher sales volumes.

MIDSTREAM AND REFINING

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Product sales					
Midstream activities	**$ 23**	$ 24	$ 21	**$ 91**	$ 82
NWRP, refined product sales and other	**206**	106	193	**670**	813
Segmented revenue	**229**	130	214	**761**	895
Less:					
NWRP, refining toll	**63**	70	65	**262**	295
Midstream activities	**5**	7	5	**22**	20
Production expense	**68**	77	70	**284**	315
NWRP, feedstock costs	**144**	82	160	**503**	669
Transportation expenses	**4**	3	4	**42**	16
Depreciation	**4**	5	3	**17**	16
Segmented earnings (loss)	**$ 9**	$ (37)	$ (23)	**$ (85)**	$ (121)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose, and the Company's 50% equity investment in North West Redwater Partnership ("NWRP").

NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 bbl/d. The refinery processes approximately 50,000 bbl/d of bitumen feedstock, including 12,500 bbl/d of bitumen feedstock for the Company (25% toll payer) and 37,500 bbl/d of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058. Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment. For the fourth quarter of 2025, production of ultra-low sulphur diesel and other refined products averaged 89,969 BOE/d (22,492 BOE/d to the Company) (three months ended September 30, 2025 – 38,434 BOE/d; 9,608 BOE/d to the Company; three months ended December 31, 2024 – 77,742 BOE/d; 19,436 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at December 31, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was $496 million (December 31, 2024 – $509 million). For the three months ended December 31, 2025, the Company's unrecognized share of the equity loss was $13 million (three months ended September 30, 2025 – recovery of unrecognized equity losses of $21 million; year ended December 31, 2025 – recovery of unrecognized equity losses of $13 million; three months ended December 31, 2024 – recovery of unrecognized equity losses of $1 million; year ended December 31, 2024 – recovery of unrecognized equity losses of $46 million).

ADMINISTRATION EXPENSE

($ millions, except per BOE amounts)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Administration expense	**$ 160**	$ 152	$ 127	**$ 615**	$ 503
$/BOE [(1)]	**$ 1.04**	$ 1.03	$ 0.95	**$ 1.07**	$ 1.02
Sales volumes (BOE/d) [(2)]	**1,672,708**	1,606,723	1,460,909	**1,575,845**	1,353,166

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

(2) Total Company sales volumes.

Administration expense for the year ended December 31, 2025 of $1.07 per BOE increased 5% from $1.02 per BOE for the year ended December 31, 2024. Administration expense for the fourth quarter of 2025 of $1.04 per BOE increased 9% from $0.95 per BOE for the fourth quarter of 2024 and was comparable with $1.03 per BOE for the third quarter of 2025. The increase in administration expense per BOE for the year ended December 31, 2025 from the year ended December 31, 2024 primarily reflected higher personnel costs, including incremental costs from recent acquisitions. The increase in administration expense per BOE for the fourth quarter of 2025 from the fourth quarter of 2024 primarily reflected higher personnel costs and lower overhead recoveries.

SHARE-BASED COMPENSATION

($ millions)	Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Share-based compensation expense	**$ 83**	$ 63	$ 44	**$ 180**	$ 279

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment; the amount of which is determined with reference to the value of the Company's shares, by individual employee performance, and the extent to which certain other performance measures are met.

The Company recognized $180 million of share-based compensation expense for the year ended December 31, 2025 primarily as a result of changes in the Company's share price, 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, and the impact of vested stock options exercised or surrendered during the period.

INTEREST AND OTHER FINANCING EXPENSE

($ millions, except effective interest rate)	Three Months Ended Dec 31 2025	Three Months Ended Sep 30 2025	Three Months Ended Dec 31 2024	Year Ended Dec 31 2025	Year Ended Dec 31 2024
Interest and other financing expense	**$ 245**	$ 93	$ 142	**$ 834**	$ 592
Less: Interest (income) and other expense (1)	**(18)**	(174)	(47)	**(205)**	(81)
Interest expense on long-term debt and lease liabilities (1)	**$ 263**	$ 267	$ 189	**$ 1,039**	$ 673
Average current and long-term debt (2)	**$ 18,103**	$ 18,802	$ 13,285	**$ 18,401**	$ 11,895
Average lease liabilities (2)	**2,008**	1,469	1,457	**1,570**	1,509
Average long-term debt and lease liabilities (2)	**$ 20,111**	$ 20,271	$ 14,742	**$ 19,971**	$ 13,404
Average effective interest rate (3) (4)	**5.1%**	5.2%	5.0%	**5.1%**	4.9%
Interest and other financing expense ($/BOE) (5)	**$ 1.60**	$ 0.62	$ 1.06	**$ 1.45**	$ 1.20
Sales volumes (BOE/d) (6)	**1,672,708**	1,606,723	1,460,909	**1,575,845**	1,353,166

(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, 2025 increased 21% to $1.45 per BOE from $1.20 per BOE for the year ended December 31, 2024. Interest and other financing expense for the fourth quarter of 2025 increased 51% to $1.60 per BOE from $1.06 per BOE for the fourth quarter of 2024 and increased 158% from $0.62 per BOE for the third quarter of 2025. The increase in interest and other financing expense per BOE for the three months and year ended December 31, 2025 from the comparable periods in 2024 primarily reflected higher average debt levels, partially offset by higher sales volumes. The increase in interest and other financing expense per BOE for the fourth quarter of 2025 from the third quarter of 2025 primarily reflected the interest income on the deferred PRT and corporate tax recoveries in the North Sea in the third quarter.

The Company's average effective interest rate for the three months and year ended December 31, 2025 was 5.1%, an increase from 4.9% for the year ended December 31, 2024, reflecting higher average long-term debt levels held in 2025, and comparable with the fourth quarter of 2024 and the third quarter of 2025.

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 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Foreign currency forward contracts	**$ (24)**	$ 52	$ 144	**$ (107)**	$ 155
Foreign currency put options [1]	**—**	—	—	**23**	—
Natural gas financial instruments [2] [3] [4] [5]	**(3)**	2	2	**(5)**	13
Net realized (gain) loss	**(27)**	54	146	**(89)**	168
Foreign currency forward contracts	**5**	—	(2)	**—**	15
Natural gas financial instruments [2] [3] [4] [5]	**6**	4	(2)	**14**	(6)
Natural gas embedded derivative [6]	**(88)**	156	—	**57**	—
Net unrealized (gain) loss	**(77)**	160	(4)	**71**	9
Net (gain) loss	**$ (104)**	$ 214	$ 142	**$ (18)**	$ 177

(1) During 2025, the Company periodically entered into foreign currency put options contracts. Further details are disclosed in note 14 to the financial statements.

(2) In the third quarter of 2025, the Company entered into fixed price financial contracts to buy 12,500 MMBtu/d of natural gas at US$1.30 AECO for the period of August to December 2025, and 25,000 MMBtu/d of natural gas at US$2.16 AECO for the period of January to December 2026.

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

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

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

(6) In the second quarter of 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 14 to the financial statements.

The Company recorded a net realized risk management gain of $89 million for the year ended December 31, 2025 and a net realized risk management gain of $27 million for the fourth quarter of 2025.

The Company recorded a net unrealized loss of $71 million ($55 million after tax of $16 million) on its risk management activities for the year ended December 31, 2025, and a net unrealized gain of $77 million ($59 million after tax of $18 million) for the fourth quarter of 2025 (three months ended September 30, 2025 – unrealized loss of $160 million ($124 million after tax of $36 million); three months ended December 31, 2024 – unrealized gain of $4 million ($3 million after tax of $1 million); year ended December 31, 2024 – unrealized loss of $9 million ($10 million after tax of $1 million)).

Further details related to outstanding derivative financial instruments as at December 31, 2025 are disclosed in note 14 to the financial statements.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net realized (gain) loss	**$ (13)**	$ 21	$ (62)	**$ 108**	$ 67
Net unrealized (gain) loss	**(193)**	269	782	**(870)**	888
Net (gain) loss [1]	**$ (206)**	$ 290	$ 720	**$ (762)**	$ 955

(1) Amounts are reported net of derivative financial instruments designated as cash flow hedges.

The net realized foreign exchange loss for the year ended December 31, 2025 was primarily related to exchange rate fluctuations on the settlement of US dollar debt, and on the settlement of working capital items denominated in US dollars. The net unrealized foreign exchange gain for the year ended December 31, 2025 was primarily related to the translation of outstanding US dollar debt. The US/Canadian dollar exchange rate as at December 31, 2025 was US$0.7292 (September 30, 2025 – US$0.7191; December 31, 2024 – US$0.6942).

INCOME TAXES

($ millions, except effective tax rates)	Three Months Ended **Dec 31 2025**	Sep 30 2025	Dec 31 2024	Year Ended **Dec 31 2025**	Dec 31 2024
North America [1]	**$ 596**	$ 499	$ 261	**$ 2,193**	$ 1,654
North Sea	**(16)**	(37)	(11)	**(124)**	(41)
Offshore Africa	**11**	—	35	**16**	57
Current PRT – North Sea	**(51)**	(45)	(67)	**(184)**	(134)
Other taxes	**3**	2	3	**10**	(5)
Current income tax	**543**	419	221	**1,911**	1,531
Deferred corporate income tax	**1,017**	(143)	372	**887**	520
Deferred PRT – North Sea	**(15)**	(389)	(145)	**(377)**	(98)
Deferred income tax	**1,002**	(532)	227	**510**	422
Income tax	**$ 1,545**	$ (113)	$ 448	**$ 2,421**	$ 1,953
Earnings before taxes	**$ 6,848**	$ 487	$ 1,586	**$ 13,241**	$ 8,059
Effective tax rate on net earnings [2]	**23%**	(23)%	28%	**18%**	24%

($ millions, except effective tax rates)	Three Months Ended **Dec 31 2025**	Sep 30 2025	Dec 31 2024	Year Ended **Dec 31 2025**	Dec 31 2024
Income tax	**$ 1,545**	$ (113)	$ 448	**$ 2,421**	$ 1,953
Tax effect on non-operating items [3]	**(1,088)**	603	143	**(481)**	175
Current PRT – North Sea	**51**	45	67	**184**	134
Deferred PRT – North Sea	**(26)**	(31)	56	**(84)**	9
Other taxes	**(3)**	(2)	(3)	**(10)**	5
Effective tax on adjusted net earnings	**$ 479**	$ 502	$ 711	**$ 2,030**	$ 2,276
Adjusted net earnings from operations [4]	**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Adjusted net earnings from operations, before taxes	**$ 2,190**	$ 2,303	$ 2,688	**$ 9,474**	$ 9,690
Effective tax rate on adjusted net earnings from operations [5] [6]	**22%**	22%	26%	**21%**	23%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, gain on disposition and remeasurement, and recoverability charges related to the North Sea and Offshore 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, 2025 and the comparable periods included the impact of non-taxable items in North America and the North Sea and the impact of differences in jurisdictional income and tax rates in the countries in which the Company operates, in relation to net earnings.

Deferred corporate income tax in North America for the three months and year ended December 31, 2025 included the deferred tax impacts of the gain on disposition and remeasurement associated with the AOSP asset swap.

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, 2025 and the comparable periods included the impact of carrybacks of abandonment expenditures related to the decommissioning activities in the North Sea. Deferred PRT and income taxes also reflected the impact of the recoverability charges recognized in depletion, depreciation and amortization expense.

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

NET CAPITAL EXPENDITURES (1) (2)

	Three Months Ended			Year Ended	
($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Exploration and Production					
Exploration and Evaluation Assets					
Net expenditures	**$ 4**	$ 18	$ 9	**$ 46**	$ 82
Net property (dispositions) acquisitions (3)	**(9)**	45	330	**69**	330
Total Exploration and Evaluation Assets	**(5)**	63	339	**115**	412
Property, Plant and Equipment					
Net property acquisitions (3)	**45**	761	2,553	**1,015**	2,642
Well drilling, completion and equipping	**514**	499	472	**2,107**	1,832
Production and related facilities	**398**	365	341	**1,560**	1,336
Other	**18**	13	14	**50**	53
Total Property, Plant and Equipment	**975**	1,638	3,380	**4,732**	5,863
Total Exploration and Production	**970**	1,701	3,719	**4,847**	6,275
Oil Sands Mining and Upgrading					
Project costs	**92**	76	66	**319**	306
Sustaining capital	**340**	312	357	**1,274**	1,466
Turnaround costs	**8**	13	16	**241**	153
Net property acquisitions (3)	**(212)**	—	6,175	**(212)**	6,173
Other	**4**	2	1	**10**	6
Total Oil Sands Mining and Upgrading	**232**	403	6,615	**1,632**	8,104
Midstream and Refining	**2**	2	1	**8**	11
Head Office	**33**	18	13	**92**	41
Net capital expenditures	**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Abandonment expenditures	**$ 201**	$ 189	$ 151	**$ 771**	$ 646
By Segment					
North America	**$ 812**	$ 1,606	$ 3,632	**$ 4,364**	$ 6,033
North Sea	**—**	5	3	**16**	39
Offshore Africa	**158**	90	84	**467**	203
Oil Sands Mining and Upgrading	**232**	403	6,615	**1,632**	8,104
Midstream and Refining	**2**	2	1	**8**	11
Head Office	**33**	18	13	**92**	41
Net capital expenditures	**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431

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

(2) Non-GAAP Financial Measure. 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. Includes cash acquired and received as net consideration of $212 million related to the AOSP asset swap within the Oil Sands Mining and Upgrading segment in the fourth quarter of 2025.

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 $6,579 million for the year ended December 31, 2025 compared with $14,431 million for the year ended December 31, 2024. Net capital expenditures were $1,237 million for the fourth quarter of 2025 compared with $10,348 million for the fourth quarter of 2024 and $2,124 million for the third quarter of 2025. In addition, the Company reported abandonment expenditures of $771 million for the year ended December 31, 2025 compared with $646 million for the year ended December 31, 2024. Abandonment expenditures were $201 million for the fourth quarter of 2025 compared with $151 million for the fourth quarter of 2024 and $189 million for the third quarter of 2025.

2026 Capital Budget

On December 16, 2025, the Company announced its 2026 operating capital budget[(1)] targeted at approximately $6,300 million. With this capital, the Company is targeting production growth in 2026 of approximately 3% from 2025, as it invests in short and medium-term production, while commencing front-end engineering and design on potential additional medium and long-term value creation opportunities. In addition, the Company targets approximately $125 million of capital related to carbon capture projects. The Company targets $993 million in abandonment expenditures for 2026. Subsequent to December 31, 2025, the Company revised its operating capital budget to $5,990 million and increased its production guidance to between 1,615,000 BOE/d and 1,665,000 BOE/d.

Annual budgets are developed and scrutinized throughout the year and can be changed, if necessary, in the context of price volatility, project returns, and the balancing of project risks and time horizons. The 2026 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.

In February 2026, subsequent to year end, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Peace River area in the North America Exploration and Production segment for cash consideration of approximately $765 million, subject to final closing adjustments. Net assets acquired primarily include exploration and evaluation assets and property, plant and equipment. The Company also assumed associated asset retirement obligations. The 2026 capital budget did not include capital related to this acquisition.

Drilling Activity [(1)] [(2)]

	Three Months Ended			Year Ended	
(number of net wells)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net successful crude oil wells [(3)]	**114**	89	100	**358**	307
Net successful natural gas wells	**20**	17	14	**78**	78
Dry wells	**1**	—	—	**2**	2
Total	**135**	106	114	**438**	387
Success rate	**99%**	100%	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 2025, the Company drilled 20 net natural gas wells, 67 net primary heavy crude oil wells, 25 net thermal bitumen wells, and 23 net light crude oil wells.

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

LIQUIDITY AND CAPITAL RESOURCES

($ millions, except ratios)	Dec 31 2025	Sep 30 2025	Dec 31 2024
Adjusted working capital [(1)]	**$ 42**	$ (303)	$ 174
Long-term debt, net [(2)]	**$ 15,944**	$ 17,155	$ 18,688
Shareholders' equity	**$ 44,366**	$ 40,461	$ 39,468
Debt to book capitalization [(2)]	**26.4%**	29.8%	32.1%
After-tax return on average capital employed [(3)]	**19.5%**	12.8%	12.7%

(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, 2025, the Company's capital resources consisted primarily of cash flows from operating activities, available bank credit facilities, and access to debt capital markets. Cash flows from operating activities and the Company's ability to renew existing bank credit facilities and raise new debt are dependent on factors discussed in the 'Business Environment' section of this MD&A and in the 'Risks and Uncertainties' section of the Company's annual MD&A for the year ended December 31, 2024. In addition, the Company's ability to renew existing bank credit facilities and raise new debt reflects current credit ratings, as determined by independent rating agencies and market conditions.

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, where appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default;
- Actively managing the allocation of capital to ensure it is expended in a prudent and appropriate manner with flexibility to adjust to market conditions. The Company continues to exercise its capital flexibility to address commodity price volatility and its impact on operating expenditures, capital commitments, and long-term debt;
- Monitoring the Company's ability to fulfill financial obligations as they become due or the ability to monetize assets in a timely manner at a reasonable price;
- Reviewing bank credit facilities and public debt indentures to ensure they are in compliance with applicable covenant packages; and
- Reviewing the Company's borrowing capacity:
  - During the first quarter of 2025, the Company extended its $500 million revolving credit facility originally maturing February 2026 to June 2027.
  - During the fourth quarter of 2025, the Company increased its $2,425 million revolving syndicated facility to $2,565 million, and extended $2,425 million originally due June 2027 to June 2029. The remaining $140 million outstanding under this facility will mature in June 2027. Each of the revolving credit facilities are extendible annually at the mutual agreement of the Company and lenders. If the facilities are not extended, the full amount of the outstanding principal would be repayable on the maturity date.
  - Borrowings under the Company's 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 reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - During the first quarter of 2025, the Company repaid US$600 million of 3.90% US dollar debt securities due February 2025.
  - During the third quarter of 2025, the Company repaid US$600 million of 2.05% US dollar debt securities due July 2025.

- During the third quarter of 2025, 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 September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During the fourth quarter of 2025, the Company issued $550 million of 3.30% medium-term notes due December 2028, $550 million of 3.75% medium-term notes due February 2031, and $550 million of 4.55% medium-term notes due February 2036. After issuing these securities, the Company had $1,350 million remaining on its base shelf prospectus.
- During the third quarter of 2025, the Company filed a base shelf prospectus that allows for the offer for sale from time to time of up to US$4,500 million of debt securities in the United States, which expires in September 2027. If issued, these securities may be offered in amounts and at prices, including interest rates, to be determined based on market conditions at the time of issuance.
- During the fourth quarter of 2025, the Company filed a prospectus supplement to the base shelf prospectus. Under the base shelf prospectus, the Company completed the exchange of US$747 million of the outstanding restricted 5.00% US dollar debt securities due December 2029 and US$750 million of the outstanding restricted 5.40% US dollar debt securities due December 2034. The exchanged notes were not subject to transfer restrictions and did not impact the Company's level of indebtedness. After the exchange of these securities, the Company had US$3,003 million remaining on its base shelf prospectus.

As at December 31, 2025, the Company had undrawn bank credit facilities of $5,668 million, and a fully drawn non-revolving term credit facility of $4,000 million. Including cash and cash equivalents, the Company had approximately $6,341 million in liquidity. The Company also has certain other dedicated credit facilities supporting letters of credit.

Long-term debt, net was $15,944 million as at December 31, 2025 (December 31, 2024 – $18,688 million), resulting in a debt to book capitalization ratio of 26.4% (December 31, 2024 – 32.1%); this ratio was within the 25% to 45% internal range utilized by management. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. The Company is subject to a financial covenant that requires debt to book capitalization as defined in its credit facility agreements to not exceed 65%. As at December 31, 2025, the Company was in compliance with this covenant.

The Company remains committed to maintaining a strong balance sheet, adequate available liquidity and a flexible capital structure. Further details related to the Company's long-term debt as at December 31, 2025 are discussed in note 7 to the financial statements.

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

As at December 31, 2025, the maturity dates of certain financial liabilities, including long-term debt and other long-term liabilities and related interest payments, were as follows:

	Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Long-term debt [(1)]	$ 441	$ 5,637	$ 2,489	$ 8,140
Other long-term liabilities [(2)]	$ 381	$ 268	$ 659	$ 1,863
Interest and other financing expense [(3)]	$ 971	$ 910	$ 1,860	$ 3,678

(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, $373 million; one to less than two years, $268 million; two to less than five years, $654 million; and thereafter, $1,811 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, 2025.

Share Capital

As at December 31, 2025, there were 2,081,578,000 common shares outstanding (December 31, 2024 – 2,102,996,000 common shares) and 54,734,000 stock options outstanding (December 31, 2024 – 50,806,000 stock options). As at March 3, 2026, the Company had 2,085,972,000 common shares outstanding and 57,252,000 stock options outstanding.

On March 4, 2026, the Board of Directors approved a 6% increase in the quarterly dividend to $0.625 per common share, beginning with the dividend payable on April 7, 2026.

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

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

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

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

For the year ended December 31, 2025, the Company purchased 33,480,000 common shares at a weighted average price of $43.28 per common share for a total cost, including tax, of $1,467 million. Retained earnings were reduced by $1,287 million, representing the excess of the purchase price of common shares over their average carrying value. Subsequent to December 31, 2025, up to and including March 3, 2026, the Company purchased 3,300,000 common shares at a weighted average price of $51.12 per common share for a total cost, including tax, of $169 million.

On March 4, 2026, 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, and applicable securities law, the purchases would be made through facilities of the TSX, alternative Canadian trading platforms, and the NYSE.

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, 2025:

($ millions)		2026		2027		2028		2029		2030		Thereafter
Product transportation, purchases, and processing (1) (2)	$	2,241	$	2,223	$	2,065	$	1,912	$	1,758	$	18,025
North West Redwater Partnership service toll (3)	$	116	$	95	$	96	$	95	$	95	$	3,878
Offshore vessels and equipment	$	99	$	—	$	—	$	—	$	—	$	—
Field equipment and power	$	50	$	26	$	26	$	24	$	24	$	170
Other	$	122	$	50	$	19	$	18	$	18	$	177

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

(2) In the fourth quarter of 2025, in connection with the AOSP asset swap, the Company became the sole contracted shipper on the Corridor pipeline. Previously, the Company recognized a commitment associated with the pipeline, however, following the completion of the AOSP asset swap the contract has been recorded as a lease. Further details on the AOSP asset swap are disclosed in note 4 to the financial statements.

(3) Pursuant to the processing agreements, the Company pays its 25% pro rata share of the debt component of the monthly fee-for-service toll. Included in the toll is $1,792 million of interest payable over the 40-year tolling period, ending in 2058.

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

LEGAL PROCEEDINGS AND OTHER CONTINGENCIES

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements requires the Company to make estimates, assumptions, and judgements in the application of IFRS Accounting Standards that have a significant impact on the financial results of the Company. Actual results may differ from estimated amounts, and those differences may be material. A comprehensive discussion of the Company's significant accounting estimates is contained in the Company's annual MD&A and audited consolidated financial statements for the year ended December 31, 2024.

CONTROL ENVIRONMENT

There have been no changes to internal control over financial reporting ("ICFR") during the year ended December 31, 2025 that have materially affected or are reasonably likely to materially affect the Company's internal control over financial reporting. Due to inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect misstatements, and even those controls determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A includes references to non-GAAP and other financial measures as defined in NI 52-112. These financial measures are used by the Company to evaluate its financial performance, financial position, and cash flow and include non-GAAP financial measures, non-GAAP ratios, total of segments measures, capital management measures, and supplementary financial measures. These financial measures are not defined by IFRS Accounting Standards 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 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Net earnings	**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Share-based compensation, net of tax (1)	**79**	59	39	**166**	257
Unrealized risk management (gain) loss, net of tax (2)	**(59)**	124	(3)	**55**	10
Unrealized foreign exchange (gain) loss, net of tax (3)	**(193)**	269	782	**(870)**	888
Realized foreign exchange (gain) loss on financing activities, net of tax (4)	**(23)**	54	—	**54**	135
Gain from investment, net of tax	**—**	—	—	**—**	(50)
Gain on acquisitions, disposition, and remeasurement, net of tax (5) (6)	**(3,845)**	—	—	**(3,925)**	—
Recoverability charges, net of tax (7) (8)	**449**	695	21	**1,144**	68
Non-operating items, net of tax	**(3,592)**	1,201	839	**(3,376)**	1,308
Adjusted net earnings from operations	**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414

(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, 2025 was an expense of $83 million (three months ended September 30, 2025 – $63 million expense; three months ended December 31, 2024 – $44 million expense; year ended December 31, 2025 – $180 million expense; year ended December 31, 2024 – $279 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 natural gas and foreign exchange. The pre-tax unrealized risk management gain for the three months ended December 31, 2025 was $77 million (three months ended September 30, 2025 – $160 million loss; three months ended December 31, 2024 – $4 million gain; year ended December 31, 2025 – $71 million loss; year ended December 31, 2024 – $9 million loss).

(3) Unrealized foreign exchange gains and losses result primarily from the translation of US dollar denominated long-term debt to period-end exchange rates and are recognized in net earnings. Pre- and after-tax amounts for these unrealized foreign exchange gains and losses are the same.

(4) Realized foreign exchange gains and losses associated with financing activities primarily result from the repayment of US dollar denominated debt and are recognized in net earnings. Pre- and after-tax amounts for these realized foreign exchange gains and losses are the same.

(5) During the second quarter of 2025, the Company acquired an interest in certain producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment, resulting in a pre- and after-tax gain on acquisition of $80 million representing the excess of the fair value of the net assets acquired compared to the total purchase consideration.

(6) During the fourth quarter of 2025, the Company completed the AOSP asset swap. As a result, the Company recognized a gain on acquisition, disposition, and remeasurement of $4,989 million ($3,845 after-tax) in net earnings. The transaction is discussed further in the 'Summary of Financial Highlights' section of this MD&A.

(7) For the three months ended December 31, 2025, the Company recognized a pre-tax non-cash recoverability charge of $204 million ($141 million after-tax) (three months ended September 30, 2025 – $1,258 million ($695 million after-tax); year ended December 31, 2025 – $1,462 million ($836 million after-tax); three months ended December 31, 2024 – $160 million ($21 million after-tax)) in depletion, depreciation and amortization expense relating to the North Sea abandonment and decommissioning activities. The costs are included in capital and abandonment expenditures, consistent with the treatment of all abandonment related expenditures for the purpose of the Company's non-GAAP measures. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

(8) For the three months ended December 31, 2025, the Company recognized pre-tax non-cash recoverability charges of $315 million ($308 million after-tax) (three months ended June 30, 2024 – $62 million ($47 million after-tax)) in depletion, depreciation and amortization expense relating to Offshore Africa. Recoverability charges are discussed in the 'Adjusted Depletion, Depreciation and Amortization – Exploration and Production' section of this MD&A.

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 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Cash flows from operating activities	**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Net change in non-cash working capital	**(134)**	(432)	563	**(672)**	743
Abandonment expenditures	**201**	189	151	**771**	646
Movements in other long-term assets (1)	**(87)**	223	40	**255**	84
Adjusted funds flow	**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859

(1) Includes the unamortized cost of contributions to the Company's employee bonus program, interest on PRT and corporate tax recoveries in the North Sea, 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 13 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 Accounting Standards.

Netback

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

The netback calculations include the realized price non-GAAP financial measure which is reconciled below to its respective line item in note 16 to the financial statements.

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

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

Realized price ($/bbl and $/BOE) is a non-GAAP ratio calculated as realized crude oil and NGLs sales and total realized BOE sales (non-GAAP financial measures) divided by respective sales volumes. Realized crude oil and NGLs sales and total realized BOE sales is comprised of crude oil and NGLs sales and natural gas sales less blending and feedstock costs and other by-product sales, as disclosed in note 16 to the financial statements. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

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

	Three Months Ended			Year Ended	
($ millions, except bbl/d and $/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs (bbl/d)					
North America	**590,144**	577,089	533,126	**570,262**	504,339
International					
North Sea	**10,804**	3,455	10,686	**9,146**	11,455
Offshore Africa	**4,318**	2,313	8,423	**4,520**	11,198
Total International	**15,122**	5,768	19,109	**13,666**	22,653
Total sales volumes	**605,266**	582,857	552,235	**583,928**	526,992
Crude oil and NGLs sales (1)	**$ 4,539**	$ 4,773	$ 4,999	**$ 19,591**	$ 19,641
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Realized crude oil and NGLs sales	**$ 3,588**	$ 3,890	$ 3,822	**$ 15,247**	$ 14,998
Realized price ($/bbl)	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

	Three Months Ended			Year Ended	
($ millions, except BOE/d and $/BOE)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Barrels of oil equivalent (BOE/d)					
North America	**1,032,973**	1,020,062	911,869	**993,279**	860,367
International					
North Sea	**11,292**	3,791	11,285	**9,656**	11,791
Offshore Africa	**4,318**	3,661	9,507	**5,575**	12,728
Total International	**15,610**	7,452	20,792	**15,231**	24,519
Total sales volumes	**1,048,583**	1,027,514	932,661	**1,008,510**	884,886
Barrels of oil equivalent sales (1)	**$ 5,247**	$ 5,139	$ 5,424	**$ 21,921**	$ 21,105
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Less: Sulphur (income) expense	**(30)**	(28)	(3)	**(85)**	3
Realized barrels of oil equivalent sales	**$ 4,326**	$ 4,284	$ 4,250	**$ 17,662**	$ 16,459
Realized price ($/BOE)	**$ 44.85**	$ 45.31	$ 49.54	**$ 47.98**	$ 50.82

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

North America – Realized Product Prices and Royalties

Realized crude oil and NGLs price ($/bbl) is a non-GAAP ratio calculated as realized crude oil and NGLs sales (non-GAAP financial measure) divided by sales volumes. Realized crude oil and NGLs sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 16 to the financial statements. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

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

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

	Three Months Ended			Year Ended	
($ millions, except $/bbl and royalty rates)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs sales (1)	**$ 4,417**	$ 4,724	$ 4,830	**$ 19,102**	$ 18,740
Less: Blending and feedstock costs (2)	**951**	883	1,177	**4,344**	4,643
Realized crude oil and NGLs sales	**$ 3,466**	$ 3,841	$ 3,653	**$ 14,758**	$ 14,097
Realized crude oil and NGLs prices ($/bbl)	**$ 63.83**	$ 72.35	$ 74.46	**$ 70.90**	$ 76.37
Crude oil and NGLs royalties (3)	**$ 525**	$ 702	$ 747	**$ 2,450**	$ 2,842
Crude oil and NGLs royalty rates	**15%**	18%	20%	**17%**	20%

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

(3) Item is a component of royalties in note 16 to the financial statements.

Realized Product Prices – Oil Sands Mining and Upgrading

Realized SCO sales price ($/bbl) is a non-GAAP ratio calculated as realized SCO sales (non-GAAP financial measure) divided by SCO sales volumes. Realized SCO sales is comprised of crude oil and NGLs sales less blending and feedstock costs, as disclosed in note 16 to the financial statements. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

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

	Three Months Ended			Year Ended	
($ millions, except for bbl/d and $/bbl)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
SCO sales volumes (bbl/d)	**624,125**	579,209	528,248	**567,335**	468,280
Crude oil and NGLs sales (1)	**$ 4,955**	$ 5,255	$ 5,362	**$ 20,112**	$ 19,263
Less: Blending and feedstock costs (2)	**597**	573	741	**2,218**	2,462
Realized SCO sales	**$ 4,358**	$ 4,682	$ 4,621	**$ 17,894**	$ 16,801
Realized SCO sales price ($/bbl)	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03

(1) Crude oil and NGLs sales in note 16 to the financial statements.

(2) Blending and feedstock costs in note 16 to the financial statements.

Net Capital Expenditures

Net capital expenditures is a non-GAAP financial measure that represents cash flows used in investing activities as presented in the Company's consolidated statements of cash flows, adjusted for the net change in non-cash working capital, 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 2025**	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Cash flows used in investing activities	**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Working capital acquired from Chevron	**—**	—	(115)	**—**	(115)
Net proceeds from investment	**—**	—	—	**—**	575
Net change in non-cash working capital	**37**	(110)	49	**(108)**	(124)
Net capital expenditures	**1,237**	2,124	10,348	**6,579**	14,431
Abandonment expenditures	**201**	189	151	**771**	646
Capital and abandonment expenditures	**$ 1,438**	$ 2,313	$ 10,499	**$ 7,350**	$ 15,077

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 2025**	Sep 30 2025	Dec 31 2024
Undrawn bank credit facilities	**$ 5,668**	$ 4,201	$ 4,562
Cash and cash equivalents	**673**	113	131
Liquidity	**$ 6,341**	$ 4,314	$ 4,693

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 12 to the financial statements. A reconciliation of the Company's long-term debt, net is presented below.

($ millions)	**Dec 31 2025**	Sep 30 2025	Dec 31 2024
Long-term debt	**$ 16,617**	$ 17,268	$ 18,819
Less: Cash and cash equivalents	**673**	113	131
Long-term debt, net	**$ 15,944**	$ 17,155	$ 18,688

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 12 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 2025**	Sep 30 2025	Dec 31 2024
Interest adjusted after-tax return:			
Net earnings, 12 months trailing (1)	**$ 10,820**	$ 6,655	$ 6,106
Interest and other financing expense, net of tax, 12 months trailing (2)	**640**	561	454
Interest adjusted after-tax return	**$ 11,460**	$ 7,216	$ 6,560
12 months average current portion long-term debt (3)	**$ 1,293**	$ 1,529	$ 1,525
12 months average long-term debt (3)	**16,149**	14,596	10,642
12 months average common shareholders' equity (3)	**41,208**	40,314	39,635
12 months average capital employed	**$ 58,650**	$ 56,439	$ 51,802
After-tax return on average capital employed	**19.5%**	12.8%	12.7%

(1) Net earnings, 12 months trailing for the fourth quarter of 2025 includes a gain on acquisition, disposition, and remeasurement of $4,989 million associated with the AOSP asset swap. Further details are disclosed in note 4 to the financial statements.

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

(3) 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.