



**Canadian Natural**

2025 ANNUAL REPORT



# 2025 Performance Highlights

The Company continues to maximize value for shareholders, with another successful year in 2025. We set several new production records, lowered operating costs and capital expenditures came in under our forecast. We grew organically and completed several accretive acquisitions, including the Palliser Block assets in southern Alberta and liquids-rich Montney assets in the Grande Prairie area, along with increasing our ownership in the Albian mines to 100% through an asset swap. We strengthened our financial position in 2025 by reducing net debt and ended the year with strong financial metrics.

	2025	2024	2023
<b>FINANCIAL</b> (\$ millions, except per common share amounts)			
Product sales <sup>(1)</sup>	\$ 44,167	\$ 41,509	\$ 40,835
Net earnings	\$ 10,820	\$ 6,106	\$ 8,233
Per common share <sup>(2)</sup> – basic	\$ 5.17	\$ 2.87	\$ 3.77
– diluted	\$ 5.16	\$ 2.85	\$ 3.74
Adjusted net earnings from operations <sup>(3)</sup>	\$ 7,444	\$ 7,414	\$ 8,533
Per common share <sup>(2)</sup> – basic <sup>(4)</sup>	\$ 3.56	\$ 3.49	\$ 3.91
– diluted <sup>(4)</sup>	\$ 3.55	\$ 3.46	\$ 3.87
Cash flows from operating activities	\$ 15,106	\$ 13,386	\$ 12,353
Adjusted funds flow <sup>(3)</sup>	\$ 15,460	\$ 14,859	\$ 15,274
Per common share <sup>(2)</sup> – basic <sup>(4)</sup>	\$ 7.39	\$ 6.99	\$ 7.00
– diluted <sup>(4)</sup>	\$ 7.37	\$ 6.94	\$ 6.93
Cash flows used in investing activities	\$ 6,687	\$ 14,095	\$ 4,858
Net capital expenditures <sup>(3)</sup>	\$ 6,579	\$ 14,431	\$ 4,909
Abandonment expenditures	\$ 771	\$ 646	\$ 509
Long-term debt, net <sup>(5)</sup>	\$ 15,944	\$ 18,688	\$ 9,922
Shareholders' equity	\$ 44,366	\$ 39,468	\$ 39,832
Debt to book capitalization <sup>(5)</sup>	26%	32%	20%

(1) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements.

(2) Per common share amounts have been updated to reflect the two for one common share split in June 2024. Further details are disclosed in the 'Advisory' section of the Company's Management's Discussion and Analysis ("MD&A") and in note 1 to the Company's audited consolidated financial statements.

(3) Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's annual MD&A included in this annual report.

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

(5) Capital Management Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A and note 15 to the Company's audited consolidated financial statements.

Cover: Jackpine Mine Extraction building.

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2025 2024 2023

**OPERATING**

**Daily production, before royalties <sup>(1)</sup>**

Crude oil and NGLs (Mbbbl/d)

North America – Exploration and Production	569	509	496
North America – Oil Sands Mining and Upgrading	565	472	451
North Sea	8	12	13
Offshore Africa	3	13	13

1,146 1,006 974

Natural gas (MMcf/d)

North America	2,538	2,136	2,139
North Sea	3	2	2
Offshore Africa	6	9	10

2,547 2,147 2,151

Barrels of oil equivalent (MBOE/d) <sup>(2)</sup>

1,571 1,363 1,332

**Drilling activity <sup>(3)</sup>**

North America	438	387	284
North Sea	—	—	—
Offshore Africa	—	—	—

438 387 284

(1) Numbers may not add due to rounding.

(2) A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet ("Mcf") of natural gas to one barrel ("bbl") of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, 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.

(3) Net wells. Excludes net stratigraphic test and service wells.

**~1,146,000**  
**BBL/D**  
**RECORD LIQUIDS PRODUCTION**

**77%**  
**OF TOTAL LIQUIDS PRODUCTION IS**  
**LONG LIFE LOW DECLINE**

# Letter to Shareholders

Canadian Natural holds one of the largest, most diversified and highest-quality portfolios in the oil and natural gas industry. Our long life low decline production base provides reliable, sustainable output, while our extensive infrastructure ownership in core areas gives us strong control over operations, costs, and market access. This affords us significant flexibility when balancing our four pillars of capital allocation: returns to shareholders, balance sheet strength, resource value growth and opportunistic acquisitions. Our operational excellence delivers industry-leading performance through safety, reliability and cost efficiency and our low maintenance capital and low break-even costs support sustainable free cash flow generation. This, combined with our strong balance sheet and financial strength, drive strong and sustainable returns to shareholders.

2025 was the best operational year in the Company's long history of maximizing value for our shareholders. We set several production records, lowered our operating costs and capital expenditures came in under our forecast. We grew organically and completed several accretive acquisitions, and as a result, we achieved record annual production of 1,571 MBOE/d in 2025, resulting in year-over-year production growth of 15% or approximately 207 MBOE/d from 2024 levels. We also achieved record annual liquids production of 1,146 Mbbl/d, of which 65% was comprised of Synthetic Crude Oil ("SCO"), light crude oil and NGLs.

Strong execution across our large, diverse asset base continues to provide significant opportunities to create shareholder value in 2026 and beyond. This is evidenced by our increased production, strong free cash flow and growth in reserves achieved in 2025, through both organic growth and accretive acquisitions. These successes provided the Board of Directors with the confidence to approve a dividend increase and an enhancement to our direct shareholder returns, by adjusting our net debt targets as a part of our free cash flow allocation policy. Additionally, as of March 5, 2026, we decreased our 2026 operating capital forecast by approximately \$310 million, following the completion of a strategic acquisition early in 2026, and increased our 2026 production guidance range to 1,615 MBOE/d and 1,665 MBOE/d from the previous guidance range of 1,590 MBOE/d and 1,650 MBOE/d.

In 2025, we generated adjusted net earnings from operations of \$7.4 billion or \$3.56 per share, and adjusted funds flow of \$15.5 billion or \$7.39 per share. Throughout the year, we completed several accretive acquisitions, increasing production and cash flow, while reducing net debt by approximately \$2.7 billion to just under \$16 billion at year end 2025. In total we returned approximately \$9.0 billion to our shareholders in 2025, including \$4.9 billion in dividends, \$1.4 billion in share repurchases and \$2.7 billion in net debt reduction.

Subsequent to year end, the Board of Directors approved a 6.4% increase to our quarterly dividend, bringing the annualized dividend up to \$2.50 per common share. This marks 2026 as the 26<sup>th</sup> consecutive year of dividend increases by Canadian Natural, with a compound annual growth rate ("CAGR") of 20% over that time, demonstrating the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.

Additionally, the Board of Directors have, effective January 1, 2026, adjusted the net debt target levels in our free cash flow allocation policy which results in an acceleration of the next increase to direct shareholder returns. Now, when net debt falls below \$16 billion, compared to our previous target of \$15 billion, we will increase direct shareholder returns in the form of share repurchases to 75% of free cash flow generated, managed on a forward-looking basis.

Our financial flexibility and long life low decline asset base provide a strong foundation and a competitive advantage with low maintenance capital requirements. Our US\$ WTI breakeven remains top tier in the low to mid-\$40 per barrel range. Our balance sheet is strong with significant liquidity of approximately \$6.3 billion at year end 2025. Our excellent results highlight the cash flow generating capability of our top tier asset base with strong year end metrics, including Debt to Book Capitalization at 26%.

**~\$9.0 BILLION**  
**RETURNED TO SHAREHOLDERS**  
**IN 2025**

**~1,571,000**  
**BOE/D**  
**RECORD TOTAL PRODUCTION**

Canadian Natural's reserves are significant when compared to other major oil companies, which support long-term organic growth opportunities. Year end 2025 total proved reserves of 15.91 billion BOE and total proved plus probable reserves of 20.75 billion BOE represent increases of approximately 4% and 3%, respectively, from year end 2024 levels. With approximately 73% of the Company's total proved reserves being long life low decline, the strength and depth of our assets is evident and provide us with a total proved reserves life index ("RLI") of 31 years and a total proved plus probable RLI of 40 years. We continue to deliver strong total proved Finding, Development and Acquisition ("FD&A") costs, including changes in Future Development Cost ("FDC"), achieving an industry leading FD&A in 2025 of \$3.64/BOE for total proved reserves and \$2.42/BOE for total proved plus probable reserves.

Canada's energy sector plays an important role in Canada's economy, providing jobs, economic growth, and reliable, affordable energy that the world needs. We believe that Canada has the people, resources, and expertise to be a global leader in oil and natural gas production.

Canadian Natural remains focused on supporting Canada in supplying safe, reliable and responsibly produced energy. We continue to incorporate environmental, social and governance practices that enhance our long-term sustainability across all aspects of our business. Our diverse, long life low decline assets are ideal for continued review and evaluation of new technologies designed to improve productivity and reduce environmental impacts.

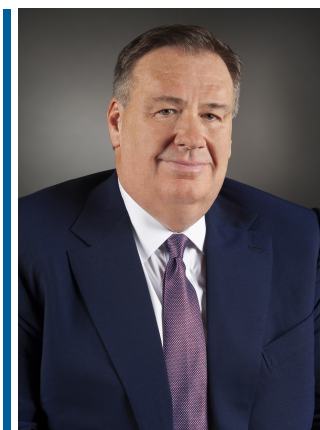
We continue to create shared value in the communities where we operate in Canada, the United Kingdom and Africa. This includes more than 24,000 landowners, over 160 municipalities and more than 80 Indigenous communities in Western Canada, as well as industry, governments, regulators, academia, and non-governmental groups. The Company is committed to working together with these diverse communities to identify opportunities for education and training, employment, business development, and community investment. At the end of 2025, our work with Indigenous businesses led to approximately \$1.1 billion in contracts being awarded during the year, a 33% increase from 2024 levels. Canadian Natural also has a strong commitment to corporate governance, which assures stakeholders that the Company always operates with the highest levels of integrity and ethical standards.

In 2026, we look to continue to deliver on our four pillars of capital allocation through our updated 2026 forecasted operating capital expenditures of approximately \$6.0 billion, along with \$993 million of abandonment expenditures and \$125 million of carbon capture expenditures. We have capital flexibility to adjust to evolving market conditions, ensuring we are allocating capital effectively, strengthening our balance sheet and maximizing value for our shareholders. We have a long track record of consistently delivering strong, industry leading results driven by our safe, reliable operations and relentless focus on continuous improvement, which maximizes long-term shareholder value.

Our team is world class and we would like to thank our employees and contractors for their hard work and focus on delivering safe, reliable, effective and efficient operations across all areas of the business. Your commitment to operational excellence and relentless focus on continuous improvement by following our mission statement underpins our ongoing success and positions Canadian Natural very well to drive long-term shareholder value into the future.



**N. MURRAY EDWARDS**  
Executive Chairman



**SCOTT G. STAUTH**  
President



**VICTOR C. DAREL**  
Chief Financial Officer



## Advisory

### SPECIAL NOTE REGARDING NON-GAAP AND OTHER FINANCIAL MEASURES

This document includes references to Non-GAAP and Other Financial Measures as defined in National Instrument 52-112 – Non-GAAP and Other Financial Measures Disclosure ("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 document and the Company's MD&A and reconciliations to the most directly comparable GAAP measure, as applicable, are provided below as well as in the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

### FREE CASH FLOW ALLOCATION POLICY

Free cash flow is a non-GAAP financial measure. The Company considers free cash flow a key measure in demonstrating the Company's ability to generate cash flow to fund future growth through capital investment, pay returns to shareholders and to repay or maintain net debt levels, pursuant to the free cash flow allocation policy.

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

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

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

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

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

The Company's free cash flow for the year ended December 31, 2025 and comparable period is shown below:

(\$ millions)	Year Ended	
	Dec 31 2025	Dec 31 2024
Adjusted funds flow <sup>(1)</sup>	\$ 15,460	\$ 14,859
Less: Dividends on common shares	4,871	4,429
Net capital expenditures <sup>(2)</sup>	6,579	5,286
Abandonment expenditures	771	646
Free cash flow	\$ 3,239	\$ 4,498

(1) Refer to the descriptions and reconciliations to the most directly comparable GAAP measure, which are provided in the 'Non-GAAP and Other Financial Measures' section of the Company's annual MD&A.

(2) Non-GAAP Financial Measure. In 2024, for the purpose of the free cash flow calculated above, net capital expenditures of \$5,286 million excludes net acquisitions of \$9,145 million. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's annual MD&A.

In March 2026, the Board of Directors adjusted the allocation of free cash flow, effective January 1, 2026, as follows:

- When net debt is at or above \$16 billion, 60% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 40% to the balance sheet.
- When net debt is between \$13 billion and \$16 billion, 75% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases and 25% to the balance sheet.
- When net debt is at or below \$13 billion, 100% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases.

## **CAPITAL BUDGET**

Capital budget (or capital forecast) is a forward-looking non-GAAP financial measure. 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 capital budget (or capital forecast) excludes abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these forecasted future expenditures. Abandonment expenditures are reported before the impact of current income tax recoveries in Canada and the UK portion of the North Sea. The Company is eligible to recover interest related to tax recoveries in the North Sea.

## **LONG-TERM DEBT, NET**

Long-term debt, net (also referred to as net debt) is a capital management measure that is calculated as current and long-term debt less cash and cash equivalents. Refer to note 15 to the Company's 2025 audited consolidated financial statements.

# 2025 Year End Reserves

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## DETERMINATION OF RESERVES

For the year ended December 31, 2025, Canadian Natural retained Independent Qualified Reserves Evaluators ("IQREs") to evaluate and review all of the Company's proved and proved plus probable reserves. The Company retained Sproule International Limited for its North America Conventional, Thermal and International reserves evaluation and review, and GLJ Ltd. for its Oil Sands Mining and Upgrading reserves evaluation. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements using forecast prices and escalated costs.

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

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

## RESERVES INFORMATION HIGHLIGHTS

A key differentiator for Canadian Natural is the strength, diversity and balance of its world class, top tier assets. The Company's total proved RLI<sup>(1)</sup> of 31 years is supported by long life low decline assets that have been strategically assembled and developed over several decades. The low maintenance capital requirements relative to the size and quality of the reserves affords the Company significant flexibility when balancing its four pillars of capital allocation to maximize shareholder value.

The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 2025 (all reserves values are Company Gross unless stated otherwise).

- Total proved reserves increased 4% to 15.910 billion BOE, with reserves additions and revisions of 1.253 billion BOE. Total proved plus probable reserves increased 3% to 20.750 billion BOE, with reserves additions and revisions of 1.213 billion BOE.
  - The strength and depth of the Company's assets are evident as approximately 73% of total proved reserves are long life low decline reserves. This results in a total proved BOE RLI of 31 years and a total proved plus probable BOE RLI of 40 years.
    - Additionally, high value, zero decline SCO and bitumen from the Horizon and Albian mines represent approximately 50% of total proved reserves with a RLI of 39 years.
- Proved developed producing reserves additions and revisions for 2025 were 1.129 billion BOE, replacing 2025 production by 197%. The proved developed producing BOE RLI is 20 years.
- Total proved reserves additions and revisions for 2025 replaced 2025 production by 218%. Total proved plus probable reserves additions and revisions for 2025 replaced 2025 production by 212%.
- In 2025, Canadian Natural continued to achieve strong FD&A costs:
  - FD&A costs, including changes in FDC, are \$3.64/BOE for total proved reserves and \$2.42/BOE for total proved plus probable reserves.
- At December 31, 2025, the net present value of Future Net Revenues ("FNR"), before income tax, discounted at 10%, was \$110.1 billion for proved developed producing reserves, \$157.8 billion for total proved reserves, and \$191.0 billion for total proved plus probable reserves.

(1) Supplementary financial measure. Refer to the notes to the '2025 Year End Reserves' on page 9.

## Summary of Company Gross Reserves

as of December 31, 2025  
Forecast Prices and Costs

	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Thermal Bitumen	Mining Bitumen	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
<b>Total Company</b>	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
Proved									
Developed Producing	121	130	188	684	835	7,043	5,861	229	10,207
Developed Non-Producing	28	6	—	42	—	—	272	13	135
Undeveloped	160	92	55	2,603	14	91	11,873	575	5,568
<b>Total Proved</b>	<b>309</b>	<b>228</b>	<b>243</b>	<b>3,330</b>	<b>849</b>	<b>7,134</b>	<b>18,006</b>	<b>817</b>	<b>15,910</b>
Probable	118	105	107	1,845	46	554	9,969	404	4,840
<b>Total Proved plus Probable</b>	<b>427</b>	<b>333</b>	<b>349</b>	<b>5,175</b>	<b>895</b>	<b>7,688</b>	<b>27,974</b>	<b>1,221</b>	<b>20,750</b>

## Reconciliation of Company Gross Reserves

as of December 31, 2025  
Forecast Prices and Costs

<b>TOTAL PROVED</b>	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Thermal Bitumen	Mining Bitumen	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
<b>Total Company</b>	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2024	252	219	255	3,312	—	7,663	16,904	713	15,231
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	16	12	—	66	—	—	113	8	121
Infill Drilling	2	17	1	9	—	—	191	36	97
Improved Recovery	—	1	3	—	—	2	—	—	6
Acquisitions	68	—	—	—	427	—	1,153	74	760
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(4)	(4)	(3)	—	—	—	(99)	(4)	(32)
Technical Revisions	1	15	2	43	426	(328)	674	28	300
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025	309	228	243	3,330	849	7,134	18,006	817	15,910

<b>TOTAL PROVED PLUS PROBABLE</b>	Light and Medium Crude Oil	Primary Heavy Crude Oil	Pelican Lake Heavy Crude Oil	Thermal Bitumen	Mining Bitumen	Synthetic Crude Oil	Natural Gas	Natural Gas Liquids	Barrels of Oil Equivalent
<b>Total Company</b>	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(MMbbl)	(Bcf)	(MMbbl)	(MMBOE)
December 31, 2024	346	318	360	5,190	—	8,255	27,156	1,116	20,110
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	22	20	—	89	—	—	167	12	171
Infill Drilling	2	26	3	11	—	—	325	54	149
Improved Recovery	—	1	4	—	—	2	—	—	7
Acquisitions	99	—	—	—	450	—	1,469	95	888
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(5)	(2)	—	—	—	(99)	(4)	(32)
Technical Revisions	(11)	5	—	(15)	449	(367)	(114)	(14)	29
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025	427	333	349	5,175	895	7,688	27,974	1,221	20,750

## NOTES TO RESERVES:

1. Company Gross reserves are working interest share before deduction of royalties and excluding any royalty interests.
2. Information in the reserves data tables may not add due to rounding. BOE values and oil and natural gas metrics may not calculate exactly due to rounding.
3. Forecast pricing assumptions utilized by the IQREs in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule International Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2025:

		2026	2027	2028	2029	2030
<b>Crude Oil and NGLs</b>						
WTI	US\$/bbl	59.92	65.10	70.28	71.93	73.37
WCS	C\$/bbl	65.13	70.43	76.90	78.71	80.29
Canadian Light Sweet	C\$/bbl	77.54	83.60	90.17	92.32	94.17
Cromer LSB	C\$/bbl	75.09	81.56	86.95	89.19	90.98
Edmonton C5+	C\$/bbl	80.01	86.19	92.83	95.04	96.94
Brent	US\$/bbl	63.92	69.13	74.36	76.10	77.62
<b>Natural Gas</b>						
AECO	C\$/MMBtu	3.00	3.30	3.49	3.58	3.65
BC Westcoast Station 2	C\$/MMBtu	2.66	3.07	3.25	3.34	3.41
Henry Hub	US\$/MMBtu	3.74	3.78	3.85	3.93	4.01

All prices increase at a rate of 2% per year after 2030.

A US\$/C\$ foreign exchange rate of 0.7277 was used for 2026, 0.7367 for 2027, and 0.7400 for 2028 and thereafter in the year end 2025 evaluation.

4. A barrel of oil equivalent ("BOE") is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6 Mcf:1 bbl). This conversion may be misleading, particularly if used in isolation, since the 6 Mcf:1 bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6 Mcf:1 bbl conversion ratio may be misleading as an indication of value.
5. Oil and natural gas metrics included herein are commonly used in the crude oil and natural gas industry and are determined by Canadian Natural as set out in the notes below. These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies and may be misleading when making comparisons. Management uses these metrics to evaluate Canadian Natural's performance over time. However, such measures are not reliable indicators of Canadian Natural's future performance and future performance may vary.
6. Reserves additions and revisions are comprised of all categories of Company Gross reserves changes, exclusive of production.
7. Reserves replacement or Production replacement ratio is the Company Gross reserves additions and revisions, for the relevant reserves category, divided by the Company Gross production in the same period.
8. Reserves Life Index ("RLI") is based on the amount for the relevant reserves category divided by the 2026 proved developed producing production forecast prepared by the IQREs.
9. Finding, Development and Acquisition ("FD&A") costs including changes in Future Development Costs ("FDC") are calculated by dividing the sum of total exploration, development and acquisition capital costs incurred in 2025 and net changes in FDC from December 31, 2024 to December 31, 2025 by the sum of total additions and revisions for the relevant reserves category. FDC excludes all abandonment, decommissioning and reclamation ("ADR") costs.
10. ADR costs included in the calculation of the Future Net Revenue ("FNR") consist of both the Company's Asset Retirement Obligation ("ARO") for North America and Offshore Africa, before inflation and discounting, for development existing as at December 31, 2025 and forecast estimates of ADR costs attributable to future development activity.

# Management's Discussion and Analysis

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## Definitions and Abbreviations

<b>AECO</b>	Alberta natural gas reference location	<b>Mbbl/d</b>	thousand barrels per day
<b>AIF</b>	Annual Information Form	<b>MBOE</b>	thousand barrels of oil equivalent
<b>AOSP</b>	Athabasca Oil Sands Project	<b>MBOE/d</b>	thousand barrels of oil equivalent per day
<b>API</b>	specific gravity measured in degrees on the American Petroleum Institute scale	<b>Mcf</b>	thousand cubic feet
<b>ARO</b>	asset retirement obligations	<b>Mcfe</b>	thousand cubic feet equivalent
<b>bbl</b>	barrel	<b>Mcf/d</b>	thousand cubic feet per day
<b>bbl/d</b>	barrels per day	<b>MMbbl</b>	million barrels
<b>Bcf</b>	billion cubic feet	<b>MMBOE</b>	million barrels of oil equivalent
<b>Bcf/d</b>	billion cubic feet per day	<b>MMBtu</b>	million British thermal units
<b>Bitumen</b>	a naturally occurring solid or semi-solid hydrocarbon consisting mainly of heavier hydrocarbons that are too heavy or thick to flow at reservoir conditions, and recoverable at economic rates using thermal in situ recovery methods	<b>MMBtu/d</b>	million British thermal units per day
		<b>MMcf</b>	million cubic feet
		<b>MMcf/d</b>	million cubic feet per day
		<b>MOU</b>	Memorandum of Understanding between the Government of Canada and the Government of Alberta.
<b>BOE</b>	barrels of oil equivalent	<b>NGLs</b>	natural gas liquids
<b>BOE/d</b>	barrels of oil equivalent per day	<b>NWRP</b>	North West Redwater Partnership
<b>Brent</b>	Dated Brent	<b>NYMEX</b>	New York Mercantile Exchange
<b>C\$</b>	Canadian dollars	<b>NYSE</b>	New York Stock Exchange
<b>CO<sub>2</sub></b>	carbon dioxide	<b>OPEC+</b>	Organization of the Petroleum Exporting Countries Plus
<b>CO<sub>2</sub>e</b>	carbon dioxide equivalents	<b>PRT</b>	Petroleum Revenue Tax
<b>CORRA</b>	Canadian Overnight Repo Rate Average	<b>SCO</b>	synthetic crude oil. Includes all crude oil blends (including mining bitumen) produced from Horizon, AOSP mines and Scotford Upgrader.
<b>Crude oil</b>	includes light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, thermal bitumen, and synthetic crude oil	<b>SEC</b>	United States Securities and Exchange Commission
		<b>SOFR</b>	Secured Overnight Financing Rate
<b>E&amp;P</b>	Exploration and Production	<b>TSX</b>	Toronto Stock Exchange
<b>FASB</b>	Financial Accounting Standards Board	<b>UK</b>	United Kingdom
<b>FPSO</b>	Floating Production, Storage and Offloading Vessel	<b>US</b>	United States
		<b>US\$</b>	United States dollars
<b>GHG</b>	greenhouse gas	<b>WCS</b>	Western Canadian Select
<b>GJ</b>	gigajoules	<b>WCS Heavy Differential</b>	WCS Heavy Differential from WTI
<b>GJ/d</b>	gigajoules per day	<b>WCSB</b>	Western Canadian Sedimentary Basin
<b>Horizon</b>	Horizon Oil Sands	<b>WTI</b>	West Texas Intermediate reference location at Cushing, Oklahoma
<b>IFRS Accounting Standards</b>	International Financial Reporting Standards as issued by the International Accounting Standards Board		
<b>Mbbl</b>	thousand barrels		

## 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, 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, NGLs, or 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 OPEC+, the impact of conflicts in the Middle East, in Ukraine and in Venezuela, the restriction or disruption of global trade routes, 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 GHG 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 MOU 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 or emissions, 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, PRODUCTION AND RESERVES**

This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the year ended December 31, 2025. It should also be read in conjunction with the Company's MD&A for the three months and year ended December 31, 2025. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's audited consolidated financial statements for the 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 2025 financial results compared to 2024 and 2023, unless otherwise indicated. In addition, this MD&A details the Company's targeted capital program for 2026. The accompanying tables form an integral part of this MD&A. Additional information relating to the Company, including its quarterly MD&A for the three months and year ended December 31, 2025, its Annual Information Form for the year ended December 31, 2025, and its audited consolidated financial statements for the year ended December 31, 2025, is available on SEDAR+ at [www.sedarplus.ca](http://www.sedarplus.ca), and on EDGAR at [www.sec.gov](http://www.sec.gov). Information on the Company's website does not form part of and is not incorporated by reference in this MD&A. This MD&A is dated March 4, 2026.

## Objectives and Strategy

The Company's objectives are to increase crude oil and natural gas production, reserves, cash flow and net asset value on a per common share basis through the economic and sustainable development of its existing crude oil and natural gas properties and through the discovery and/or acquisition of new reserves. The Company strives to meet these objectives and its commitments to environmental stewardship and safety excellence.

The Company endeavors to meet these objectives by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a balanced approach to growth and investments, and focuses on creating long-term shareholder value, including through its dividend and share buyback programs, in accordance with its capital allocation policy. The Company allocates its capital by maintaining:

- Balance among its products, namely light and medium crude oil and NGLs, primary heavy crude oil, Pelican Lake heavy crude oil<sup>(1)</sup>, thermal bitumen, SCO, and natural gas;
- A large, balanced, diversified, high quality, long life low decline asset base;
- Balance among acquisitions, development and exploration;
- Balance between sources and terms of debt financing and a strong financial position; and
- Commitment to environmental stewardship throughout the decision-making process.

The Company's three-phase crude oil marketing strategy includes:

- Blending various crude oil streams with diluents to create more attractive feedstock;
- Expanding market access for crude oil and natural gas by supporting and participating in pipeline and infrastructure projects that add incremental transportation capacity to existing and new markets; and
- Supporting and participating in projects that will increase the downstream conversion capacity for heavy crude oil and thermal bitumen.

Operational discipline, safe, effective and efficient operations, and cost control are fundamental to the Company and embrace the key piece of the Company's mission statement: "doing it right". By consistently managing costs throughout all cycles of the industry, the Company believes it will achieve continued growth. Effective and efficient operations and cost control are attained by developing area knowledge, and by maintaining high working interests and operator status in the Company's properties.

The Company is committed to maintaining a strong balance sheet and flexible capital structure. The Company believes it has built the necessary financial capacity to develop its reserves, execute on growth projects and take advantage of favourable acquisition opportunities. Additionally, the Company periodically utilizes its risk management hedging program to reduce the risk of volatility in commodity prices and foreign exchange rates, and corresponding cash flows.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used a combination of internally generated cash flows and debt and equity financing to selectively acquire properties generating future cash flows in its core areas. The Company's financial discipline, commitment to a strong balance sheet, and capacity to internally generate cash flows provide the means to responsibly and sustainably grow in the long term.

(1) Pelican Lake heavy crude oil is 12–17° API oil, which receives medium quality crude netbacks due to lower production expense and lower royalty rates.

## Financial and Operational Highlights

(\$ millions, except per common share amounts)	2025		2024		2023 <sup>(1)</sup>	
Product sales <sup>(2)</sup>	\$	<b>44,167</b>	\$	41,509	\$	40,835
Crude oil and NGLs	\$	<b>40,740</b>	\$	39,084	\$	37,300
Natural gas	\$	<b>2,450</b>	\$	1,568	\$	2,575
Net earnings	\$	<b>10,820</b>	\$	6,106	\$	8,233
Per common share – basic	\$	<b>5.17</b>	\$	2.87	\$	3.77
– diluted	\$	<b>5.16</b>	\$	2.85	\$	3.74
Adjusted net earnings from operations <sup>(3)</sup>	\$	<b>7,444</b>	\$	7,414	\$	8,533
Per common share – basic <sup>(4)</sup>	\$	<b>3.56</b>	\$	3.49	\$	3.91
– diluted <sup>(4)</sup>	\$	<b>3.55</b>	\$	3.46	\$	3.87
Cash flows from operating activities	\$	<b>15,106</b>	\$	13,386	\$	12,353
Adjusted funds flow <sup>(3)</sup>	\$	<b>15,460</b>	\$	14,859	\$	15,274
Per common share – basic <sup>(4)</sup>	\$	<b>7.39</b>	\$	6.99	\$	7.00
– diluted <sup>(4)</sup>	\$	<b>7.37</b>	\$	6.94	\$	6.93
Dividends declared per common share <sup>(5)</sup>	\$	<b>2.35</b>	\$	2.14	\$	1.85
Total assets	\$	<b>91,830</b>	\$	85,359	\$	75,955
Long-term debt, net <sup>(6)</sup>	\$	<b>15,944</b>	\$	18,688	\$	9,922
Cash flows used in investing activities	\$	<b>6,687</b>	\$	14,095	\$	4,858
Net capital expenditures <sup>(3)</sup>	\$	<b>6,579</b>	\$	14,431	\$	4,909
Abandonment expenditures	\$	<b>771</b>	\$	646	\$	509
Average realized price						
Crude oil and NGLs – Exploration and Production (\$/bbl) <sup>(4)</sup>	\$	<b>71.54</b>	\$	77.76	\$	72.36
Natural gas – Exploration and Production (\$/Mcf) <sup>(7)</sup>	\$	<b>2.51</b>	\$	1.86	\$	3.10
SCO – Oil Sands Mining and Upgrading (\$/bbl) <sup>(4)</sup>	\$	<b>86.41</b>	\$	98.03	\$	100.06
Daily production, before royalties (BOE/d)		<b>1,570,757</b>		1,363,496		1,332,105
Crude oil and NGLs (bbl/d)		<b>1,146,175</b>		1,005,603		973,530
Natural gas (MMcf/d) <sup>(8)</sup>		<b>2,547</b>		2,147		2,151

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

(2) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements.

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

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

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

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

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

(8) Natural gas production volumes approximate sales volumes.

### CONSOLIDATED NET EARNINGS AND ADJUSTED NET EARNINGS FROM OPERATIONS

For 2025, the Company reported net earnings of \$10,820 million compared with \$6,106 million for 2024 (2023 – \$8,233 million). Net earnings for 2025 included non-operating income, net of tax, of \$3,376 million compared with non-operating losses of \$1,308 million for 2024 (2023 – non-operating losses of \$300 million) 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 2025 were \$7,444 million compared with \$7,414 million for 2024 (2023 – \$8,533 million).

The increase in net earnings and adjusted net earnings from operations for 2025 compared with 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<sup>(1)</sup> in the Oil Sands Mining and Upgrading segment; and
- lower realized crude oil and NGLs pricing<sup>(1)</sup> in the North America Exploration and Production segment.

A detailed reconciliation of the changes in the Company's product sales is provided in the 'Analysis of Changes in Product Sales' section of this MD&A.

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 increase in net earnings for 2025 from 2024. 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 6 to the Company's audited consolidated financial statements.

## **CASH FLOWS FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW**

Cash flows from operating activities for 2025 were \$15,106 million compared with \$13,386 million for 2024 (2023 – \$12,353 million). The increase in cash flows from operating activities for 2025 from 2024 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 2025 was \$15,460 million (\$7.39 per common share) compared with \$14,859 million (\$6.99 per common share) for 2024 (2023 – \$15,274 million; \$7.00 per common share<sup>(2)</sup>). The increase in adjusted funds flow for 2025 from 2024 was primarily due to the factors noted above related to the increase 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 PRT and corporate tax recoveries, and prepaid cost of service tolls.

## **PRODUCTION VOLUMES**

Record crude oil and NGLs production before royalties for 2025 of 1,146,175 bbl/d increased 14% from 1,005,603 bbl/d in 2024 (2023 – 973,530 bbl/d). Natural gas production before royalties for 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d in 2024 (2023 – 2,151 MMcf/d). Total production before royalties for 2025 of 1,570,757 BOE/d increased 15% from 1,363,496 BOE/d in 2024 (2023 – 1,332,105 BOE/d). Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production' section of this MD&A.

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

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

## PRODUCT PRICES

In the Company's Exploration and Production segments, the 2025 realized crude oil and NGLs prices decreased 8% to average \$71.54 per bbl from \$77.76 per bbl in 2024 (2023 – \$72.36 per bbl), and the 2025 realized natural gas price increased 35% to average \$2.51 per Mcf from \$1.86 per Mcf in 2024 (2023 – \$3.10 per Mcf). In the Oil Sands Mining and Upgrading segment, the Company's 2025 realized SCO sales price averaged \$86.41 per bbl, a decrease of 12% from \$98.03 per bbl in 2024 (2023 – \$100.06 per bbl). 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 and Outlook', '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, the 2025 crude oil and NGLs production expense<sup>(1)</sup> averaged \$14.33 per bbl, comparable with \$14.72 per bbl in 2024 (2023 – \$16.12 per bbl), and natural gas production expense<sup>(1)</sup> averaged \$1.14 per Mcf in 2025, a decrease of 7% from \$1.22 per Mcf in 2024 (2023 – \$1.30 per Mcf). In the Oil Sands Mining and Upgrading segment, the 2025 production expense<sup>(1)</sup> averaged \$22.66 per bbl, comparable with \$22.88 per bbl in 2024 (2023 – \$24.32 per bbl). 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.

## 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)

2025	Total	Dec 31	Sep 30	Jun 30	Mar 31
Product sales <sup>(1)</sup>	\$ 44,167	\$ 10,710	\$ 11,070	\$ 9,675	\$ 12,712
Crude oil and NGLs	\$ 40,740	\$ 9,666	\$ 10,468	\$ 8,874	\$ 11,732
Natural gas	\$ 2,450	\$ 735	\$ 399	\$ 600	\$ 716
Net earnings	\$ 10,820	\$ 5,303	\$ 600	\$ 2,459	\$ 2,458
Net earnings per common share					
– basic	\$ 5.17	\$ 2.55	\$ 0.29	\$ 1.17	\$ 1.17
– diluted	\$ 5.16	\$ 2.54	\$ 0.29	\$ 1.17	\$ 1.17
2024	Total	Dec 31	Sep 30	Jun 30	Mar 31 <sup>(2)</sup>
Product sales <sup>(1)</sup>	\$ 41,509	\$ 11,064	\$ 10,401	\$ 10,622	\$ 9,422
Crude oil and NGLs	\$ 39,084	\$ 10,381	\$ 9,943	\$ 10,084	\$ 8,676
Natural gas	\$ 1,568	\$ 451	\$ 257	\$ 331	\$ 529
Net earnings	\$ 6,106	\$ 1,138	\$ 2,266	\$ 1,715	\$ 987
Net earnings per common share					
– basic	\$ 2.87	\$ 0.54	\$ 1.07	\$ 0.80	\$ 0.46
– diluted	\$ 2.85	\$ 0.54	\$ 1.06	\$ 0.80	\$ 0.46

(1) Further details related to product sales are disclosed in note 21 to the Company's audited consolidated financial statements.

(2) Common share, per common share, dividend, and stock option amounts have been updated to reflect the two for one common share split. Further details are disclosed in the 'Advisory' section of this MD&A and in note 1 to the Company's audited consolidated 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 2024, the impact of the WCS Heavy Differential from WTI in North America, and the impact of the differential between WTI and 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.

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

- **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 2024, the acquisition of assets in the Palliser block and the Grande Prairie area in 2025, and the AOSP asset swap in 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 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 2024, and the acquisition of assets in the Palliser block and the Grande Prairie area in 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 and Outlook

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 WCSB. The ongoing ramp-up of LNG Canada is expected to further increase LNG demand and support AECO pricing in 2026.

During 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

(Yearly average)		2025	2024	2023
WTI benchmark price (US\$/bbl)	\$	<b>64.77</b>	\$ 75.72	\$ 77.61
Dated Brent benchmark price (US\$/bbl)	\$	<b>69.02</b>	\$ 80.75	\$ 82.61
WCS Heavy Differential from WTI (US\$/bbl)	\$	<b>11.10</b>	\$ 14.73	\$ 18.62
SCO price (US\$/bbl)	\$	<b>64.42</b>	\$ 75.09	\$ 79.64
Condensate benchmark price (US\$/bbl)	\$	<b>63.32</b>	\$ 72.94	\$ 76.55
NYMEX benchmark price (US\$/MMBtu)	\$	<b>3.43</b>	\$ 2.27	\$ 2.74
AECO benchmark price (C\$/GJ)	\$	<b>1.76</b>	\$ 1.36	\$ 2.77
US/Canadian dollar average exchange rate (US\$)	\$	<b>0.7155</b>	\$ 0.7300	\$ 0.7409
US/Canadian dollar year end exchange rate (US\$)	\$	<b>0.7292</b>	\$ 0.6942	\$ 0.7573

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 2025, a decrease of 14% from US\$75.72 per bbl for 2024 (2023 – US\$77.61 per bbl).

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 2025, a decrease of 15% from US\$80.75 per bbl for 2024 (2023 – US\$82.61 per bbl).

The decrease in WTI and Brent benchmark pricing for 2025 from 2024 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 2025 compared with US\$14.73 per bbl for 2024 (2023 – US\$18.62 per bbl). The narrowing of the WCS Heavy Differential for 2025 from 2024 primarily reflected full year takeaway capacity on the TMX pipeline and strong US Gulf Coast heavy oil pricing.

The SCO price averaged US\$64.42 per bbl for 2025, a decrease of 14% from US\$75.09 per bbl for 2024 (2023 – US\$79.64 per bbl). The decrease in SCO pricing for 2025 from 2024 primarily reflected weaker WTI benchmark pricing.

NYMEX benchmark pricing averaged US\$3.43 per MMBtu for 2025, an increase of 51% from US\$2.27 per MMBtu for 2024 (2023 – US\$2.74 per MMBtu). The increase in NYMEX natural gas pricing for 2025 from 2024 primarily reflected lower US inventory levels in the first half of 2025, combined with record LNG exports out of the US Gulf Coast.

AECO benchmark pricing averaged \$1.76 per GJ for 2025, an increase of 29% from \$1.36 per GJ for 2024 (2023 – \$2.77 per GJ). The increase in AECO natural gas pricing for 2025 from 2024 primarily reflected higher NYMEX benchmark pricing and increased exports out of the WCSB.

## Analysis of Changes in Product Sales

(\$ millions)	2023	Changes due to			2024	Changes due to			2025
		Volumes	Prices	Other		Volumes	Prices	Other	
<b>North America</b>									
Crude oil and NGLs	\$ 17,375	\$ 283	\$ 1,082	\$ —	\$ 18,740	\$ 2,392	\$ (2,030)	\$ —	\$ 19,102
Natural gas	2,375	3	(963)	—	1,415	261	611	—	2,287
Other <sup>(1)</sup>	10	—	—	(4)	6	—	—	86	92
	19,760	286	119	(4)	20,161	2,653	(1,419)	86	21,481
<b>North Sea</b>									
Crude oil and NGLs	435	30	2	—	467	(95)	(47)	—	325
Natural gas	7	1	(1)	—	7	4	2	—	13
Other <sup>(1)</sup>	—	—	—	4	4	—	—	(4)	—
	442	31	1	4	478	(91)	(45)	(4)	338
<b>Offshore Africa</b>									
Crude oil and NGLs	577	(142)	(1)	—	434	(260)	(10)	—	164
Natural gas	51	(7)	(2)	—	42	(13)	1	—	30
Other <sup>(1)</sup>	9	—	—	(5)	4	—	—	(3)	1
	637	(149)	(3)	(5)	480	(273)	(9)	(3)	195
<b>Oil Sands Mining and Upgrading</b>									
Crude oil and NGLs	18,661	823	(221)	—	19,263	4,138	(3,289)	—	20,112
Other <sup>(1)</sup>	5	—	—	11	16	—	—	188	204
	18,666	823	(221)	11	19,279	4,138	(3,289)	188	20,316
<b>Midstream and Refining</b>									
Midstream activities	76	—	—	6	82	—	—	9	91
Refined product sales and other <sup>(1)</sup>	926	—	—	(113)	813	—	—	(143)	670
	1,002	—	—	(107)	895	—	—	(134)	761
<b>Inter-segment Elimination and Other <sup>(2)</sup></b>									
Product sales	318	—	—	(116)	202	—	—	864	1,066
Other <sup>(1)</sup>	10	—	—	4	14	—	—	(4)	10
	328	—	—	(112)	216	—	—	860	1,076
<b>Total</b>	<b>\$ 40,835</b>	<b>\$ 991</b>	<b>\$ (104)</b>	<b>\$ (213)</b>	<b>\$ 41,509</b>	<b>\$ 6,427</b>	<b>\$ (4,762)</b>	<b>\$ 993</b>	<b>\$ 44,167</b>

(1) Includes the sale of diesel and other refined products, and other income.

(2) Eliminates internal transportation and electricity charges and includes production, processing and other purchasing and selling activities that are not included in the above segments.

Product sales increased 6% to \$44,167 million for 2025 from \$41,509 million for 2024 (2023 – \$40,835 million). The increase in total product sales was primarily due to higher SCO sales volumes in the Oil Sands Mining and Upgrading segment; and higher crude oil and NGLs sales volumes, together with higher realized natural gas pricing and sales volumes in the North America Exploration and Production segment; partially offset by lower realized SCO pricing and lower realized crude oil and NGLs pricing in the Oil Sands Mining and Upgrading and North America Exploration and Production segments, respectively. Crude oil and NGLs and natural gas pricing are discussed in detail in the 'Business Environment and Outlook', 'Exploration and Production' and 'Oil Sands Mining and Upgrading' sections of this MD&A. Crude oil and NGLs and natural gas production volumes are discussed in detail in the 'Daily Production' section of this MD&A.

For 2025, 1% of the Company's crude oil and NGLs and natural gas product sales were generated outside of North America (2024 – 2%; 2023 – 3%). North Sea accounted for 1% of crude oil and NGLs and natural gas product sales for 2025 (2024 – 1%; 2023 – 1%), and Offshore Africa accounted for less than 1% of crude oil and NGLs and natural gas product sales for 2025 (2024 – 1%; 2023 – 2%).

# Daily Production

## DAILY PRODUCTION, BEFORE ROYALTIES

	2025	2024	2023
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	569,401	509,288	496,100
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	565,102	472,245	451,339
International – Exploration and Production			
North Sea	8,468	11,536	12,639
Offshore Africa	3,204	12,534	13,452
Total International <sup>(2)</sup>	11,672	24,070	26,091
Total Crude oil and NGLs	1,146,175	1,005,603	973,530
<b>Natural gas (MMcf/d) <sup>(3)</sup></b>			
North America	2,538	2,136	2,139
International			
North Sea	3	2	2
Offshore Africa	6	9	10
Total International	9	11	12
Total Natural gas	2,547	2,147	2,151
Total Barrels of oil equivalent (BOE/d)	1,570,757	1,363,496	1,332,105
<b>Product mix</b>			
Light and medium crude oil and NGLs	11%	10%	10%
Pelican Lake heavy crude oil	3%	3%	3%
Primary heavy crude oil	6%	6%	6%
Thermal bitumen	17%	20%	20%
Synthetic crude oil <sup>(1)</sup>	36%	35%	34%
Natural gas	27%	26%	27%
<b>Percentage of product sales <sup>(1) (4) (5)</sup></b>			
Crude oil and NGLs	94%	96%	93%
Natural gas	6%	4%	7%

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

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

(3) Natural gas production volumes approximate sales volumes.

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

(5) Excluding Midstream and Refining revenue.

## DAILY PRODUCTION, NET OF ROYALTIES

	2025	2024	2023
<b>Crude oil and NGLs (bbl/d)</b>			
North America – Exploration and Production	<b>476,850</b>	408,237	406,534
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	<b>467,415</b>	386,171	385,996
International – Exploration and Production			
North Sea	<b>8,451</b>	11,509	12,609
Offshore Africa	<b>3,061</b>	11,918	12,183
Total International	<b>11,512</b>	23,427	24,792
Total Crude oil and NGLs	<b>955,777</b>	817,835	817,322
<b>Natural gas (MMcf/d)</b>			
North America	<b>2,466</b>	2,091	2,055
International			
North Sea	<b>3</b>	2	2
Offshore Africa	<b>6</b>	9	10
Total International	<b>9</b>	11	12
Total Natural gas	<b>2,475</b>	2,102	2,067
Total Barrels of oil equivalent (BOE/d)	<b>1,368,198</b>	1,168,209	1,161,852

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

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

Total 2025 production before royalties averaged 1,570,757 BOE/d, an increase of 15% from 1,363,496 BOE/d in 2024 (2023 – 1,332,105 BOE/d).

Record crude oil and NGLs production before royalties for 2025 averaged 1,146,175 bbl/d, an increase of 14% from 1,005,603 bbl/d for 2024 (2023 – 973,530 bbl/d). The increase in crude oil and NGLs production before royalties for 2025 from 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.

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.

Natural gas production before royalties accounted for 27% of the Company's total production in 2025 on a BOE basis. Record natural gas production before royalties for 2025 averaged 2,547 MMcf/d, an increase of 19% from 2,147 MMcf/d for 2024 (2023 – 2,151 MMcf/d). The increase in natural gas production before royalties for 2025 from 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 2025 averaged 569,401 bbl/d, an increase of 12% from 509,288 bbl/d for 2024 (2023 – 496,100 bbl/d). The increase in North America crude oil and NGLs production before royalties for 2025 from 2024 primarily reflected the acquisitions completed in December 2024 and in the second and third quarters of 2025, combined with strong drilling results.

Thermal oil production before royalties for 2025 averaged 275,086 bbl/d, comparable with 271,011 bbl/d for 2024 (2023 – 262,000 bbl/d).

Pelican Lake heavy crude oil production before royalties averaged 42,470 bbl/d for 2025, a decrease of 5% from 44,779 bbl/d for 2024 (2023 – 47,078 bbl/d) reflecting Pelican Lake's long life low decline production.

Record North America natural gas production before royalties for 2025 averaged 2,538 MMcf/d, an increase of 19% from 2,136 MMcf/d for 2024 (2023 – 2,139 MMcf/d). The increase in natural gas production before royalties for 2025 from 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 2025 averaged 565,102 bbl/d, an increase of 20% from 472,245 bbl/d for 2024 (2023 – 451,339 bbl/d). The increase in SCO production before royalties for 2025 from 2024 primarily reflected the acquisition completed in December 2024, combined with strong utilization.

### International – Exploration and Production

International crude oil and NGLs production before royalties for 2025 averaged 11,672 bbl/d, a decrease of 52% from 24,070 bbl/d for 2024 (2023 – 26,091 bbl/d). The decrease in International crude oil and NGLs production before royalties for 2025 from 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.

## Exploration and Production

### OPERATING HIGHLIGHTS

	2025		2024		2023	
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>						
Realized price <sup>(2)</sup>	\$	<b>71.54</b>	\$	77.76	\$	72.36
Transportation <sup>(3)</sup>		<b>7.02</b>		5.50		4.23
Realized price, net of transportation <sup>(2)</sup>		<b>64.52</b>		72.26		68.13
Royalties <sup>(4)</sup>		<b>11.53</b>		14.85		12.55
Production expense <sup>(5)</sup>		<b>14.33</b>		14.72		16.12
Netback <sup>(2)</sup>	\$	<b>38.66</b>	\$	42.69	\$	39.46
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>						
Realized price <sup>(6)</sup>	\$	<b>2.51</b>	\$	1.86	\$	3.10
Transportation <sup>(3)</sup>		<b>0.59</b>		0.62		0.56
Realized price, net of transportation		<b>1.92</b>		1.24		2.54
Royalties <sup>(4)</sup>		<b>0.08</b>		0.05		0.13
Production expense <sup>(5)</sup>		<b>1.14</b>		1.22		1.30
Netback <sup>(7)</sup>	\$	<b>0.70</b>	\$	(0.03)	\$	1.11
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>						
Realized price <sup>(2)</sup>	\$	<b>47.98</b>	\$	50.82	\$	50.54
Transportation <sup>(3)</sup>		<b>5.54</b>		4.78		3.88
Realized price, net of transportation <sup>(2)</sup>		<b>42.44</b>		46.04		46.66
Royalties <sup>(4)</sup>		<b>6.90</b>		8.96		7.77
Production expense <sup>(5)</sup>		<b>11.18</b>		11.73		12.74
Netback <sup>(2)</sup>	\$	<b>24.36</b>	\$	25.35	\$	26.15

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

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

(3) Calculated as 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

	2025	2024	2023
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America <sup>(2)</sup>	\$ 70.90	\$ 76.37	\$ 70.51
International average <sup>(3)</sup>	\$ 98.07	\$ 108.80	\$ 107.46
North Sea <sup>(3)</sup>	\$ 97.26	\$ 111.53	\$ 110.99
Offshore Africa <sup>(3)</sup>	\$ 99.71	\$ 106.00	\$ 106.25
Crude oil and NGLs average <sup>(2)</sup>	\$ 71.54	\$ 77.76	\$ 72.36
<b>Natural gas (\$/Mcf) <sup>(1) (3)</sup></b>			
North America	\$ 2.47	\$ 1.81	\$ 3.04
International average	\$ 12.45	\$ 12.01	\$ 12.81
North Sea	\$ 11.77	\$ 9.93	\$ 10.45
Offshore Africa	\$ 12.77	\$ 12.46	\$ 13.19
Natural gas average	\$ 2.51	\$ 1.86	\$ 3.10
Average (\$/BOE) <sup>(1) (2)</sup>	\$ 47.98	\$ 50.82	\$ 50.54

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

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

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

### North America

North America realized crude oil and NGLs prices decreased 7% to average \$70.90 per bbl for 2025 from \$76.37 per bbl for 2024 (2023 – \$70.51 per bbl), primarily reflecting lower WTI benchmark pricing, partially offset by a narrowing of the WCS Heavy Differential.

The Company remains focused on its crude oil blending and marketing strategy, which includes expanding market access within existing pipeline infrastructure, supporting pipeline projects that increase transportation capacity to new markets, and collaborating with refiners to enhance heavy conversion capacity. During 2025, the Company contributed approximately 223,000 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 2025 from \$1.81 per Mcf for 2024 (2023 – \$3.04 per Mcf). The increase in realized natural gas prices per Mcf for 2025 from 2024 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:

(Yearly average)	2025	2024	2023
<b>Wellhead Price <sup>(1)</sup></b>			
Light and medium crude oil and NGLs (\$/bbl)	\$ 65.77	\$ 69.42	\$ 70.72
Pelican Lake heavy crude oil (\$/bbl)	\$ 75.07	\$ 82.83	\$ 77.69
Primary heavy crude oil (\$/bbl)	\$ 73.74	\$ 81.97	\$ 75.67
Thermal bitumen (\$/bbl)	\$ 72.42	\$ 76.57	\$ 67.62
Natural gas (\$/Mcf)	\$ 2.47	\$ 1.81	\$ 3.04

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

### International

International realized crude oil and NGLs prices averaged \$98.07 per bbl for 2025, a decrease of 10% from \$108.80 per bbl for 2024 (2023 – \$107.46 per bbl). Realized crude oil and NGLs prices per bbl in any particular year 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

	2025	2024	2023
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America	\$ 11.77	\$ 15.40	\$ 12.89
International average	\$ 1.56	\$ 2.75	\$ 5.99
North Sea	\$ 0.15	\$ 0.26	\$ 0.33
Offshore Africa	\$ 4.41	\$ 5.30	\$ 10.08
Crude oil and NGLs average	\$ 11.53	\$ 14.85	\$ 12.55
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
North America	\$ 0.08	\$ 0.04	\$ 0.13
Offshore Africa	\$ 0.59	\$ 0.57	\$ 0.62
Natural gas average	\$ 0.08	\$ 0.05	\$ 0.13
Average (\$/BOE) <sup>(1)</sup>	\$ 6.90	\$ 8.96	\$ 7.77

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

### North America

Government royalties on a significant portion of North America crude oil and NGLs production fall under the oil sands royalty regime and are calculated on a project by project basis as a percentage of gross revenue less production, capital, and abandonment costs incurred.

North America crude oil and NGLs and natural gas royalties for 2025 and the comparable periods reflected movements in benchmark commodity prices, fluctuations in the WCS Heavy Differential and the impact of sliding scale royalty rates.

Crude oil and NGLs royalty rates<sup>(1)</sup> averaged approximately 17% of product sales for 2025 compared with 20% of product sales for 2024 (2023 – 18%). The decrease in royalty rates for 2025 from 2024 primarily reflected lower benchmark pricing and the impact of sliding scale royalty rates.

Natural gas royalty rates averaged approximately 3% of product sales for 2025 compared with 2% of product sales for 2024 (2023 – 4%). The increase in royalty rates for 2025 from 2024 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 2025 compared with 5% of product sales for 2024 (2023 – 9%). Royalty rates as a percentage of product sales reflected the timing of liftings, and the status of payout in the various fields.

## PRODUCTION EXPENSE – EXPLORATION AND PRODUCTION

	2025	2024	2023
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>			
North America	\$ 12.19	\$ 12.55	\$ 14.46
International average	\$ 103.48	\$ 62.99	\$ 48.16
North Sea	\$ 136.47	\$ 103.28	\$ 85.57
Offshore Africa	\$ 36.73	\$ 21.77	\$ 21.14
Crude oil and NGLs average	\$ 14.33	\$ 14.72	\$ 16.12
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>			
North America	\$ 1.11	\$ 1.19	\$ 1.27
International average	\$ 9.23	\$ 6.51	\$ 7.26
North Sea	\$ 12.18	\$ 8.95	\$ 9.85
Offshore Africa	\$ 7.80	\$ 5.98	\$ 6.83
Natural gas average	\$ 1.14	\$ 1.22	\$ 1.30
Average (\$/BOE) <sup>(1)</sup>	\$ 11.18	\$ 11.73	\$ 12.74

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

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

## North America

North America crude oil and NGLs production expense for 2025 averaged \$12.19 per bbl, comparable with \$12.55 per bbl for 2024 (2023 – \$14.46 per bbl).

North America natural gas production expense for 2025 averaged \$1.11 per Mcf, a decrease of 7% from \$1.19 per Mcf for 2024 (2023 – \$1.27 per Mcf). The decrease in natural gas production expense per Mcf for 2025 from 2024 primarily reflected higher production volumes.

## International

International crude oil and NGLs production expense for 2025 averaged \$103.48 per bbl, an increase of 64% from \$62.99 per bbl for 2024 (2023 – \$48.16 per bbl). The increase in crude oil and NGLs production expense per bbl for 2025 from 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.

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

(\$ millions, except per BOE amounts)	2025		2024		2023	
North America	\$	4,582	\$	3,831	\$	3,679
North Sea		1,573		279		494
Offshore Africa		432		297		213
Depletion, depreciation and amortization	\$	6,587	\$	4,407	\$	4,386
Less: Recoverability charges <sup>(1)</sup>		1,777		222		436
Adjusted depletion, depreciation and amortization <sup>(2)</sup>	\$	4,810	\$	4,185	\$	3,950
\$/BOE <sup>(3)</sup>	\$	13.07	\$	12.92	\$	12.27

(1) During 2024, 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 2025 of \$13.07 per BOE was comparable with \$12.92 per BOE for 2024 (2023 – \$12.27 per BOE).

## 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 costs were higher than originally budgeted. Accordingly, the Company updated its abandonment and decommissioning cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni and Thelma fields). Additionally, 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. Cessation of production has been accelerated to the first quarter of 2027 and associated crude oil reserves were de-booked. As a result, the Company recognized a non-cash charge of \$836 million (2024 – \$21 million; 2023 – \$113 million), comprised of a recoverability charge recognized in depletion, depreciation and amortization expense of \$1,462 million (2024 – \$160 million; 2023 – \$436 million), net of deferred tax recoveries of \$626 million (2024 – \$139 million; 2023 – \$323 million).

In Offshore Africa, 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, 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

(\$ millions, except per BOE amounts)	2025		2024		2023
North America	\$	221	\$	231	\$ 234
North Sea		64		65	46
Offshore Africa		9		9	8
Asset retirement obligation accretion	\$	294	\$	305	\$ 288
\$/BOE <sup>(1)</sup>	\$	0.80	\$	0.94	\$ 0.89

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for 2025 of \$0.80 per BOE decreased 15% from \$0.94 per BOE for 2024 (2023 – \$0.89 per BOE). The decrease in asset retirement obligation accretion expense per BOE for 2025 from 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.

## Oil Sands Mining and Upgrading

### OPERATING HIGHLIGHTS

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 565,102 bbl/d in 2025, reflecting the acquisition completed in December 2024, combined with strong utilization. Additionally, the Company successfully completed the AOSP asset swap with Shell during the fourth quarter of 2025.

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

(\$/bbl)	2025		2024		2023
Realized SCO sales price <sup>(1)</sup>	\$	86.41	\$	98.03	\$ 100.06
Bitumen value for royalty purposes <sup>(2)</sup>	\$	66.23	\$	72.68	\$ 65.43
Bitumen royalties <sup>(3)</sup>	\$	13.84	\$	17.23	\$ 14.43
Transportation <sup>(4)</sup>	\$	3.31	\$	2.91	\$ 1.89

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

(2) Calculated as the annual 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 2025, a decrease of 12% from \$98.03 per bbl for 2024 (2023 – \$100.06 per bbl). The decrease in realized SCO sales price per bbl for 2025 from 2024 primarily reflected lower WTI benchmark pricing.

Bitumen royalties averaged \$13.84 per bbl for 2025, a decrease from \$17.23 per bbl for 2024 (2023 – \$14.43 per bbl) primarily reflecting the decrease in average bitumen value for royalty purposes and the impact of royalty true-ups.

Transportation expense averaged \$3.31 per bbl for 2025, an increase of 14% from \$2.91 per bbl for 2024 (2023 – \$1.89 per bbl). The increase in transportation expense per bbl for 2025 from 2024 primarily reflected higher volumes shipped on the TMX pipeline in 2025.

## PRODUCTION EXPENSE – OIL SANDS MINING AND UPGRADING

The following tables are reconciled to the Oil Sands Mining and Upgrading production expense disclosed in note 21 to the Company's audited consolidated financial statements.

(\$ millions)		2025		2024		2023
Production expense, excluding natural gas costs	\$	4,543	\$	3,801	\$	3,794
Natural gas costs		150		120		195
Production expense	\$	4,693	\$	3,921	\$	3,989
(\$/bbl)		2025		2024		2023
Production expense, excluding natural gas costs <sup>(1)</sup>	\$	21.94	\$	22.18	\$	23.13
Natural gas costs <sup>(2)</sup>		0.72		0.70		1.19
Production expense <sup>(3)</sup>	\$	22.66	\$	22.88	\$	24.32
Sales volumes (bbl/d)		567,335		468,280		449,282

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

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

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

Production expense for 2025 of \$22.66 per bbl was comparable with \$22.88 per bbl for 2024 (2023 – \$24.32 per bbl).

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

(\$ millions, except per bbl amounts)		2025		2024		2023
Depletion, depreciation and amortization	\$	2,780	\$	2,258	\$	2,011
\$/bbl <sup>(1)</sup>	\$	13.42	\$	13.17	\$	12.26

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

Depletion, depreciation and amortization expense for 2025 of \$13.42 per bbl was comparable with \$13.17 per bbl for 2024 (2023 – \$12.26 per bbl).

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

(\$ millions, except per bbl amounts)		2025		2024		2023
Asset retirement obligation accretion	\$	86	\$	84	\$	78
\$/bbl <sup>(1)</sup>	\$	0.42	\$	0.49	\$	0.48

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

Asset retirement obligation accretion expense represents the increase in the carrying amount of the asset retirement obligation due to the passage of time. Asset retirement obligation accretion expense for 2025 of \$0.42 per bbl decreased 14% from \$0.49 per bbl for 2024 (2023 – \$0.48 per bbl). The decrease in asset retirement obligation accretion expense per bbl for 2025 from 2024 primarily reflected the impact of higher sales volumes.

## Midstream and Refining

(\$ millions)	2025	2024	2023
Product sales			
Midstream activities	\$ 91	\$ 82	\$ 76
NWRP, refined product sales and other	670	813	926
Segmented revenue	761	895	1,002
Less:			
NWRP, refining toll	262	295	303
Midstream activities	22	20	29
Production expense	284	315	332
NWRP, feedstock costs	503	669	646
Transportation expenses	42	16	18
Depreciation	17	16	16
Segmented loss	\$ (85)	\$ (121)	\$ (10)

The Company's Midstream and Refining assets consist of two crude oil pipeline systems, a 50% working interest in an 84-megawatt cogeneration plant at Primrose, and the Company's 50% equity investment in NWRP. Approximately 25% of the Company's crude oil production is transported through its fully owned and operated Pelican Lake and ECHO pipelines to Edmonton and Hardisty, Alberta, providing access to international export pipelines. Ownership of these midstream pipeline assets enables the Company to control transportation costs and generate third-party revenue.

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. Production of ultra-low sulphur diesel and other refined products for 2025 averaged 68,139 BOE/d (17,035 BOE/d to the Company) (2024 – 76,664 BOE/d; 19,166 BOE/d to the Company; 2023 – 81,525 BOE/d; 20,381 BOE/d to the Company), reflecting the 25% toll payer commitment.

As at December 31, 2025, NWRP had \$1,583 million (December 31, 2024 – \$1,459 million) outstanding under its unsecured commercial paper program. NWRP has a \$1,900 million syndicated credit facility that reserves capacity for amounts outstanding under its commercial paper program and for a debt service reserve equal to six months of anticipated facility interest and fees. As at December 31, 2025, the facility was undrawn.

During 2025, NWRP repaid and cancelled \$250 million of the non-revolving portion of the syndicated credit facility.

During 2024, NWRP amended its syndicated credit facility to extend the revolving portion originally maturing June 2025 to June 2027, and reduce the authorized limit on the revolving portion by \$275 million to \$1,900 million. In 2024, NWRP repaid \$657 million on its non-revolving facility, and reduced the authorized limit to \$250 million.

As at December 31, 2025, NWRP had \$8,750 million in long-term notes outstanding (December 31, 2024 – \$8,750 million).

During 2024, NWRP repaid \$500 million of 3.20% series A bonds. Additionally, in 2024 NWRP issued \$700 million of 4.85% series P bonds due June 2034 and \$600 million of 5.08% series Q bonds due June 2054.

NWRP also has short-term borrowings under a \$300 million syndicated credit facility ("demand operating facility") (December 31, 2024 – \$300 million). As at December 31, 2025, NWRP had borrowings of \$50 million under the demand operating facility (December 31, 2024 – \$103 million).

As at December 31, 2025, the Company's cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$496 million (2024 – \$509 million). The Company's recovery of unrecognized equity losses from NWRP for 2025 was \$13 million (2024 – recovery of unrecognized equity losses of \$46 million; 2023 – unrecognized equity loss of \$4 million).

## Corporate and Other

### ADMINISTRATION EXPENSE

(\$ millions, except per BOE amounts)	2025	2024	2023
Administration expense	\$ 615	\$ 503	\$ 452
\$/BOE <sup>(1)</sup>	\$ 1.07	\$ 1.02	\$ 0.93
Sales volumes (BOE/d) <sup>(2)</sup>	1,575,845	1,353,166	1,331,092

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

(2) Total Company sales volumes.

Administration expense for 2025 of \$1.07 per BOE increased 5% from \$1.02 per BOE for 2024 (2023 – \$0.93 per BOE). Administration expense per BOE increased from 2024 primarily reflecting higher personnel costs, including incremental costs from recent acquisitions.

### SHARE-BASED COMPENSATION

(\$ millions)	2025	2024	2023
Share-based compensation expense	\$ 180	\$ 279	\$ 491

The Company's Stock Option Plan provides employees with the right to receive common shares or a cash payment in exchange for stock options surrendered. The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment; the amount of which is determined with reference to the value of the Company's shares, 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 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. An expense of \$30 million related to PSUs granted to certain executive employees was included in the share-based compensation expense for 2025 (2024 – \$77 million expense; 2023 – \$70 million expense).

### INTEREST AND OTHER FINANCING EXPENSE

(\$ millions, except effective interest rate)	2025	2024	2023
Interest and other financing expense	\$ 834	\$ 592	\$ 636
Less: Interest (income) and other expense <sup>(1)</sup>	(205)	(81)	(55)
Interest expense on long-term debt and lease liabilities <sup>(1)</sup>	\$ 1,039	\$ 673	\$ 691
Average current and long-term debt <sup>(2)</sup>	\$ 18,401	\$ 11,895	\$ 12,749
Average lease liabilities <sup>(2)</sup>	1,570	1,509	1,500
Average long-term debt and lease liabilities <sup>(2)</sup>	\$ 19,971	\$ 13,404	\$ 14,249
Average effective interest rate <sup>(3) (4)</sup>	5.1%	4.9%	4.8%
Interest and other financing expense (\$/BOE) <sup>(5)</sup>	\$ 1.45	\$ 1.20	\$ 1.31
Sales volumes (BOE/d) <sup>(6)</sup>	1,575,845	1,353,166	1,331,092

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

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

(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 Company's audited consolidated 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 for the respective year. 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 2025 increased 21% to \$1.45 per BOE from \$1.20 per BOE for 2024 (2023 – \$1.31 per BOE). The increase in interest and other financing expense per BOE for 2025 from 2024 primarily reflected higher average debt levels, partially offset by higher sales volumes.

The Company's average effective interest rate of 5.1% for 2025 increased from 4.9% for 2024 primarily reflecting higher average long-term debt levels held in 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.

(\$ millions)	2025	2024	2023
Foreign currency forward contracts	\$ (107)	\$ 155	\$ (17)
Foreign currency put options <sup>(1)</sup>	23	—	—
Natural gas financial instruments <sup>(2) (3) (4) (5)</sup>	(5)	13	3
Net realized (gain) loss	(89)	168	(14)
Foreign currency forward contracts	—	15	(9)
Natural gas financial instruments <sup>(2) (3) (4) (5)</sup>	14	(6)	21
Natural gas embedded derivative <sup>(6)</sup>	57	—	—
Net unrealized loss	71	9	12
Net (gain) loss	\$ (18)	\$ 177	\$ (2)

(1) During 2025, the Company periodically entered into foreign currency put options contracts. Further details are disclosed in note 18 to the Company's audited consolidated financial statements.

(2) In 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 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 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 2020.

(6) In 2025, the Company entered into a long-term natural gas supply agreement containing an embedded derivative. Further details are disclosed in note 18 to the Company's audited consolidated financial statements.

During 2025, the Company recorded a net realized risk management gain of \$89 million primarily related to the settlement of foreign currency forward contracts.

The Company recorded a net unrealized loss of \$71 million (\$55 million after tax of \$16 million) on its risk management activities for 2025 (2024 – \$9 million unrealized loss (\$10 million after tax of \$1 million); 2023 – \$12 million unrealized loss (\$7 million after tax of \$5 million)).

Further details related to outstanding derivative financial instruments as at December 31, 2025 are disclosed in note 18 to the Company's audited consolidated financial statements.

## FOREIGN EXCHANGE

(\$ millions)	2025	2024	2023
Net realized loss (gain)	\$ 108	\$ 67	\$ (19)
Net unrealized (gain) loss	(870)	888	(260)
Net (gain) loss <sup>(1)</sup>	\$ (762)	\$ 955	\$ (279)

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

The net realized foreign exchange loss for 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 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 (December 31, 2024 – US\$0.6942; December 31, 2023 – US\$0.7573).

## INCOME TAXES

(\$ millions, except effective tax rates)	2025	2024	2023
North America <sup>(1)</sup>	\$ 2,193	\$ 1,654	\$ 1,853
North Sea	(124)	(41)	(6)
Offshore Africa	16	57	73
Current PRT – North Sea	(184)	(134)	(58)
Other taxes	10	(5)	17
Current income tax	1,911	1,531	1,879
Deferred corporate income tax	887	520	267
Deferred PRT – North Sea	(377)	(98)	(214)
Deferred income tax	510	422	53
Income tax	\$ 2,421	\$ 1,953	\$ 1,932
Earnings before taxes	\$ 13,241	\$ 8,059	\$ 10,165
Effective tax rate on net earnings <sup>(2)</sup>	18%	24%	19%

(\$ millions, except effective tax rates)	2025	2024	2023
Income tax	\$ 2,421	\$ 1,953	\$ 1,932
Tax effect on non-operating items <sup>(3)</sup>	(481)	175	345
Current PRT – North Sea	184	134	58
Deferred PRT – North Sea	(84)	9	9
Other taxes	(10)	5	(17)
Effective tax on adjusted net earnings	\$ 2,030	\$ 2,276	\$ 2,327
Adjusted net earnings from operations <sup>(4)</sup>	\$ 7,444	\$ 7,414	\$ 8,533
Adjusted net earnings from operations, before taxes	\$ 9,474	\$ 9,690	\$ 10,860
Effective tax rate on adjusted net earnings from operations <sup>(5) (6)</sup>	21%	23%	21%

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

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

(3) Includes the net income tax effect on PSUs, certain stock options, unrealized risk management, 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 Company's audited consolidated 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 2025 and the comparable years 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 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 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.

During 2025, the Company filed Scientific Research and Experimental Development claims of approximately \$240 million (2024 – \$273 million; 2023 – \$380 million) relating to qualifying research and development expenditures for Canadian income tax purposes.

## Net Capital Expenditures <sup>(1) (2)</sup>

(\$ millions)	2025	2024	2023
<b>EXPLORATION AND PRODUCTION</b>			
<b>Exploration and Evaluation Assets</b>			
Net expenditures	\$ 46	\$ 82	\$ 47
Net property acquisitions (dispositions) <sup>(3)</sup>	69	330	(3)
Total Exploration and Evaluation Assets	115	412	44
<b>Property, Plant and Equipment</b>			
Net property acquisitions <sup>(3)</sup>	1,015	2,642	24
Well drilling, completion and equipping	2,107	1,832	1,579
Production and related facilities	1,560	1,336	1,267
Other	50	53	61
Total Property, Plant and Equipment	4,732	5,863	2,931
Total Exploration and Production	4,847	6,275	2,975
<b>OIL SANDS MINING AND UPGRADING</b>			
Project costs	319	306	348
Sustaining capital	1,274	1,466	1,347
Turnaround costs	241	153	189
Net property acquisitions <sup>(3)</sup>	(212)	6,173	5
Other	10	6	5
Total Oil Sands Mining and Upgrading	1,632	8,104	1,894
<b>Midstream and Refining</b>	8	11	10
<b>Head office</b>	92	41	30
<b>Net capital expenditures</b>	\$ 6,579	\$ 14,431	\$ 4,909
<b>Abandonment expenditures</b>	\$ 771	\$ 646	\$ 509
<b>By Segment</b>			
North America	\$ 4,364	\$ 6,033	\$ 2,770
North Sea	16	39	33
Offshore Africa	467	203	172
Oil Sands Mining and Upgrading	1,632	8,104	1,894
Midstream and Refining	8	11	10
Head office	92	41	30
<b>Net capital expenditures</b>	\$ 6,579	\$ 14,431	\$ 4,909

(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 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 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 for 2025 were \$6,579 million compared with \$14,431 million for 2024. 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.

## CAPITAL SPENDING

On December 16, 2025, the Company announced its 2026 operating capital budget<sup>(1)</sup> 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 forecast 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 <sup>(1) (2)</sup>

(number of net wells)	2025	2024	2023
Net successful crude oil wells <sup>(3)</sup>	358	307	221
Net successful natural gas wells	78	78	61
Dry wells	2	2	2
Total	438	387	284
Success rate	99%	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 2025, the Company drilled 78 net natural gas wells, 198 net primary heavy crude oil wells, 16 net Pelican Lake heavy crude oil wells, 78 net thermal bitumen wells, and 68 net light crude oil wells.

## Liquidity and Capital Resources

(\$ millions, except ratios)	2025	2024	2023
Adjusted working capital <sup>(1)</sup>	\$ 42	\$ 174	\$ 712
Long-term debt, net <sup>(2)</sup>	\$ 15,944	\$ 18,688	\$ 9,922
Shareholders' equity	\$ 44,366	\$ 39,468	\$ 39,832
Debt to book capitalization <sup>(2)</sup>	26%	32%	20%
After-tax return on average capital employed <sup>(3)</sup>	20%	13%	17%

(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 and Outlook' section and in the 'Risks and Uncertainties' section of this MD&A. 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.

(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.

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 2025, the Company extended its \$500 million revolving credit facility originally maturing February 2026 to June 2027. During 2024, the Company extended its \$500 million revolving credit facility from February 2025 to February 2026. During 2023, the Company extended its \$500 million revolving credit facility from February 2024 to February 2025.
  - During 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.
  - During 2024, the Company extended its \$2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028.
  - During 2024 and in connection with the acquisition of Chevron's assets, the Company entered into a \$4,000 million non-revolving term credit facility maturing December 2027.
  - Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.
  - The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.
  - During 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 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 2024, the Company repaid \$320 million of 3.55% medium-term notes.
  - During 2024, the Company issued \$500 million of 4.15% medium-term notes due December 2031.
  - During 2025, the Company repaid US\$600 million of 3.90% US dollar debt securities due February 2025, and US\$600 million of 2.05% US dollar debt securities due July 2025.
  - During 2024, the Company repaid US\$500 million of 3.80% US dollar debt securities.
  - During 2024, the Company issued US\$750 million of 5.00% notes due December 2029 and US\$750 million of 5.40% notes due December 2034.
  - During 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 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, resulting in a debt to book capitalization ratio of 26% (December 31, 2024 – 32%; December 31, 2023 – 20%); 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 10 to the Company's audited consolidated financial statements.

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

The Company periodically utilizes commodity derivative financial instruments under its commodity hedge policy to reduce the risk of volatility in commodity prices and to support the Company's cash flow for its capital expenditure programs. This policy currently allows for the hedging of up to 60% of the near 12 months budgeted production and up to 40% of the following 13 to 24 months estimated production. For the purpose of this policy, the purchase of commodity put options is in addition to the above parameters. Further details related to the Company's commodity derivative financial instruments outstanding as at December 31, 2025 are discussed in note 18 to the Company's audited consolidated financial statements.

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 <sup>(1)</sup>	\$	441	\$ 5,637	\$ 2,489	\$ 8,140
Other long-term liabilities <sup>(2)</sup>	\$	381	\$ 268	\$ 659	\$ 1,863
Interest and other financing expense <sup>(3)</sup>	\$	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<sup>(1)</sup> per common share.

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

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

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

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 <sup>(1) (2) (3) (4)</sup>	\$ 2,241	\$ 2,223	\$ 2,065	\$ 1,912	\$ 1,758	18,025
North West Redwater Partnership service toll <sup>(5)</sup>	\$ 116	\$ 95	\$ 96	\$ 95	\$ 95	3,878
Offshore vessels and equipment	\$ 99	\$ —	\$ —	\$ —	\$ —	—
Field equipment and power <sup>(4)</sup>	\$ 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 2023, and is subject to change pending the approval of final tolls.

(2) In 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 6 to the Company's audited consolidated financial statements.

(3) During 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(4) During 2024, the acquisition of Chevron's assets included approximately \$1,292 million of product transportation and processing commitments and approximately \$75 million of field equipment and power commitments.

(5) 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.

## Reserves

For the years ended December 31, 2025 and 2024, the Company retained Independent Qualified Reserves Evaluators to evaluate and review all of the Company's total proved and total proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements.

The following are reconciliation tables of the Company gross total proved and total proved plus probable reserves using forecast prices and costs as at the effective date of December 31, 2025:

<b>Total Proved</b>	<b>Light and Medium Crude Oil</b> (MMbbl)	<b>Primary Heavy Crude Oil</b> (MMbbl)	<b>Pelican Lake Heavy Crude Oil</b> (MMbbl)	<b>Thermal Bitumen</b> (MMbbl)	<b>Mining Bitumen<sup>(2)</sup></b> (MMbbl)	<b>Synthetic Crude Oil<sup>(2)</sup></b> (MMbbl)	<b>Natural Gas</b> (Bcf)	<b>Natural Gas Liquids</b> (MMbbl)	<b>Barrels of Oil Equivalent</b> (MMBOE)
December 31, 2024 <sup>(1)</sup>	252	219	255	3,312	—	7,663	16,904	713	15,231
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	16	12	—	66	—	—	113	8	121
Infill Drilling	2	17	1	9	—	—	191	36	97
Improved Recovery	—	1	3	—	—	2	—	—	6
Acquisitions	68	—	—	—	427	—	1,153	74	760
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(4)	(4)	(3)	—	—	—	(99)	(4)	(32)
Technical Revisions	1	15	2	43	426	(328)	674	28	300
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025 <sup>(1)</sup>	<b>309</b>	<b>228</b>	<b>243</b>	<b>3,330</b>	<b>849</b>	<b>7,134</b>	<b>18,006</b>	<b>817</b>	<b>15,910</b>

<b>Total Proved Plus Probable</b>	<b>Light and Medium Crude Oil</b> (MMbbl)	<b>Primary Heavy Crude Oil</b> (MMbbl)	<b>Pelican Lake Heavy Crude Oil</b> (MMbbl)	<b>Thermal Bitumen</b> (MMbbl)	<b>Mining Bitumen<sup>(2)</sup></b> (MMbbl)	<b>Synthetic Crude Oil<sup>(2)</sup></b> (MMbbl)	<b>Natural Gas</b> (Bcf)	<b>Natural Gas Liquids</b> (MMbbl)	<b>Barrels of Oil Equivalent</b> (MMBOE)
December 31, 2024 <sup>(1)</sup>	346	318	360	5,190	—	8,255	27,156	1,116	20,110
Discoveries	—	—	—	—	—	—	—	—	—
Extensions	22	20	—	89	—	—	167	12	171
Infill Drilling	2	26	3	11	—	—	325	54	149
Improved Recovery	—	1	4	—	—	2	—	—	7
Acquisitions	99	—	—	—	450	—	1,469	95	888
Dispositions	—	—	—	—	—	—	—	—	—
Economic Factors	(5)	(5)	(2)	—	—	—	(99)	(4)	(32)
Technical Revisions	(11)	5	—	(15)	449	(367)	(114)	(14)	29
Production	(26)	(32)	(16)	(100)	(4)	(202)	(930)	(38)	(573)
December 31, 2025 <sup>(1)</sup>	<b>427</b>	<b>333</b>	<b>349</b>	<b>5,175</b>	<b>895</b>	<b>7,688</b>	<b>27,974</b>	<b>1,221</b>	<b>20,750</b>

(1) Information in the reserves data tables may not add due to rounding. BOE values as presented may not calculate due to rounding.

(2) Except as disaggregated in the 'Reserves' section of this MD&A, all references to Synthetic Crude Oil also include Mining Bitumen within the product streams produced by Horizon, AOSP mines, and the Scotford Upgrader in this MD&A.

At December 31, 2025, the Company's total proved crude oil, thermal bitumen, mining bitumen, SCO, and NGLs reserves were 12,909 MMbbl, and total proved plus probable crude oil, thermal bitumen, mining bitumen, SCO, and NGLs reserves were 16,088 MMbbl. Total proved reserves additions and revisions replaced 218% of 2025 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions, and future offset additions amounted to 741 MMbbl, and additions to total proved plus probable reserves amounted to 889 MMbbl. Net positive revisions amounted to 173 MMbbl for total proved reserves and 33 MMbbl for total proved plus probable reserves, primarily due to technical revisions.

At December 31, 2025, the total proved natural gas reserves were 18,006 Bcf, and total proved plus probable natural gas reserves were 27,974 Bcf. Total proved reserves additions and revisions replaced 218% of 2025 production. Additions to total proved reserves resulting from exploration and development activities, acquisitions, dispositions, and future offset additions

amounted to 1,457 Bcf, and additions to total proved plus probable reserves amounted to 1,961 Bcf. Net positive revisions amounted to 574 Bcf for total proved reserves, primarily due to technical revisions. Net negative revisions amounted to 213 Bcf for total proved plus probable reserves, due to technical revisions and decreasing commodity prices.

The Reserves Committee of the Company's Board of Directors has met with and carried out independent due diligence procedures with each of the Company's Independent Qualified Reserves Evaluators to review the qualifications of and procedures used by each evaluator in determining the estimate of the Company's quantities and related net present value of future net revenue of the remaining reserves. Additional reserves information is annually disclosed in the AIF.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States FASB Topic 932 "Extractive Activities – Oil and Gas" in the Company's annual report on Form 40-F filed with the SEC and in the 'Supplementary Oil and Gas Information' section of the Company's annual report.

## Risks and Uncertainties

The Company is exposed to various operational risks inherent in the exploration, development, production and marketing of crude oil and NGLs and natural gas and the mining, extracting and upgrading of bitumen into SCO. These inherent risks include, but are not limited to, the following:

- Volatility in the prevailing prices of crude oil and NGLs, natural gas and refined products;
- The ability to find, produce, and replace reserves, whether sourced from exploration, improved recovery or acquisitions, at a reasonable cost, including the risk of reserves revisions due to economic and technical factors. Reserves revisions can have a positive or negative impact on asset valuations, ARO and depletion rates;
- Reservoir quality and uncertainty of reserves estimates;
- Regulatory risk associated with project or facility expansions, or for exploration and development activities, which can add to costs or cause delays in projects;
- Labour risk associated with securing the manpower necessary to complete capital projects in a timely and cost effective manner;
- Operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting and upgrading the Company's bitumen products;
- Timing and success of integrating the business and operations of acquired companies and assets;
- Credit risk related to non-payment for sales contracts or non-performance by counterparties to contracts, including derivative financial instruments and physical sales contracts as part of a hedging program;
- Interest rate risk associated with the Company's ability to secure financing on commercially acceptable terms;
- Foreign exchange risk due to the effect of fluctuating exchange rates on the Company's US dollar denominated debt and revenue from sales predominantly based on US dollar denominated benchmarks;
- Environmental risk associated with exploration and development activities, including associated GHG emissions;
- Future legislative and regulatory developments related to environmental regulation, including but not limited to GHG compliance costs and reduction targets, and emissions caps;
- The timing and pace of change to a low carbon economy is uncertain and the ability to access insurance and capital may be adversely affected in the event that financial institutions, investors, insurers, rating agencies and/or lenders adopt more restrictive decarbonisation policies;
- Potential actions of governments, regulatory authorities and other stakeholders that may result in costs or restrictions in the jurisdictions where the Company has operations, including but not limited to restrictions on production and the certainty and timelines for regulatory approval processes;
- Geopolitical risks associated with changing governments or governmental policies, social instability and other political, economic or diplomatic developments in the regions where the Company has its operations;
- International trade risk with key trading partners, including the imposition of tariffs or other trade measures on the Company's products or goods and services used by the Company in its supply chain, including the imposition of countermeasures by the government of Canada, the duration and extent of which may be uncertain;
- Changing royalty regimes;
- The ability to secure adequate transportation for products, which could be affected by pipeline constraints, the construction by third parties of new or expansion of existing pipeline capacity and other factors;
- The access to markets for the Company's products;

- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's data security, intellectual property and operations, and/or result in a material privacy breach;
- Business interruptions because of unexpected events such as fires or explosions whether caused by human error or nature, severe storms and other calamitous acts of nature, blowouts, droughts, freeze-ups, mechanical or equipment failures of facilities and infrastructure and other similar events affecting the Company or other parties whose operations or assets directly or indirectly impact the Company and that may or may not be financially recoverable;
- Epidemics or pandemics have the potential to disrupt the Company's operations, projects and financial condition through the disruption of the local or global supply chain and transportation services, or the loss of Company manpower resulting from quarantines (as was the case with the COVID-19 pandemic). Depending on the severity, a large scale epidemic or pandemic could impact international demand for commodities and have a corresponding impact on the prices realized by the Company, which could have a material adverse effect on the Company's financial condition;
- Liquidity risk related to the Company's ability to fulfill financial obligations as they become due or ability to liquidate assets in a timely manner at a reasonable price; and
- Other circumstances affecting revenue and expenses.

The Company uses a variety of means to seek to mitigate and/or minimize these risks. The Company maintains a comprehensive property loss and business interruption insurance program to reduce risk. Operational control is enhanced by focusing efforts on large core areas with high working interests and by assuming operatorship of key facilities. Product mix is diversified, consisting of the production of natural gas and the production of crude oil of various grades and NGLs. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Accounts receivable from the sale of crude oil and natural gas are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company seeks to manage these risks by monitoring exposure to individual customers, contractors, suppliers and joint venture partners on a regular basis and when appropriate, ensuring parental guarantees or letters of credit are in place, and as applicable, taking other mitigating actions to minimize the impact in the event of a default. Derivative financial instruments are periodically utilized to help ensure targets are met and to manage commodity price, foreign currency, and interest rate exposures. The Company is exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company seeks to manage this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions. Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due. The Company has implemented cyber security protocols and procedures designed to reduce the risk of failure or a significant breach of the Company's information technology systems and related data and control systems.

The Company has safety, asset integrity and environmental management systems to recover and process crude oil and natural gas resources safely and efficiently while being committed to environmental stewardship.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

For additional details regarding the Company's risks and uncertainties, refer to the Company's AIF for the year ended December 31, 2025.

## Environment

The Company has a Corporate Statement on Environmental Management which affirms that environmental stewardship is a fundamental value of the Company. As part of the Company's commitment to environmental stewardship, the Company includes and evaluates environmental, social, economic, and health considerations in new project designs and in operations, where appropriate. The Company invests in people, facilities and infrastructure, as well as new and proven technologies (including technologies designed to improve environmental performance), to recover and process crude oil and natural gas resources efficiently and in an environmentally responsible manner. When working with local communities, the Company considers the interests and values of the people using the land in proximity to its operations and, where appropriate, adapts projects to recognize or accommodate these concerns.

The Company has processes in place and is committed to complying with all existing environmental standards and regulations and has included appropriate amounts in its capital budget to continue to meet current environmental protection requirements; however there are no assurances that the effect of future environmental laws and regulations will not have a material effect on the Company's business, financial condition and results of operations. The crude oil and natural gas industry is experiencing incremental increases in costs related to environmental regulation compliance, particularly in North America and the North Sea. Existing and expected legislation and regulations may require the Company to address and take steps to mitigate the effect of its activities on the environment. To address some of these concerns, the Company's environmental risk management strategy includes working constructively with legislators and regulators on any new or revised policies, legislation or regulations to

reflect a balanced approach to sustainable development. However, increasingly stringent laws and regulations may have an adverse effect on the Company's future net earnings.

The environmental risk management strategies employed by the Company are based upon an Environmental Management Plan (the "Plan") that incorporates targets and measurements against which the Company's environmental performance is measured, all of which is presented to, and reviewed by, the Board of Directors quarterly.

As part of the Company's environmental stewardship and risk management, the Company engages in research (often through collaborative efforts with industry partners, governments and research institutions) designed to develop, assess and implement new or improved technologies and innovative practices that are intended to improve environmental performance.

The Plan, in conjunction with the Company's operating practices and guidelines, has been adopted with the intention of reducing the environmental impact of operations while meeting: regulatory requirements; regional management frameworks for air quality and emissions, ground and surface water, and biodiversity; industry operating standards and guidelines, and internal corporate standards. Adequate and proper training of, and diligent execution by, the Company's operators and contractors is key to the effectiveness of the Company's environmental management programs and supports efforts to reduce the Company's environmental footprint. The Company, as part of this Plan, has implemented proactive programs that include:

- Implementation of various GHG emissions and methane reduction programs, and optimization programs that seek to improve efficiencies at the Company's facilities;
- Environmental planning to assess potential impacts by the Company's operations and implement avoidance strategies and mitigation programs that seek to maintain biodiversity for terrestrial and aquatic systems and high value ecosystems;
- Continued evaluation of new technologies designed to reduce environmental impacts from operations, including support for Canada's Oil Sands Innovation Alliance ("COSIA"), the innovation arm of Pathways, Petroleum Technology Alliance Canada ("PTAC") and other research institutions;
- Water management programs that are designed to improve recycle rates and reduce fresh water use;
- Groundwater monitoring for all thermal in situ and mine operations;
- Reclamation and decommissioning programs across the Company's operations. In North America, well abandonment and progressive reclamation of large contiguous areas of land supports biodiversity and functional wildlife habitats. In the Company's International operations, decommissioning activities continued at the Ninian Hub and stakeholder engagement was completed ahead of formally submitting the Ninian South Decommissioning Program for regulatory approval in December 2025;
- Tailings management in Oil Sands Mining intended to reduce fine tailings and promote progressive reclamation;
- Monitoring programs to assess changes to biodiversity, wildlife and fisheries in order to manage construction and operations impacts and to assess reclamation success;
- Participation in the joint Alberta / Federal government Oil Sands Monitoring Program which supports the regional monitoring of air, surface water, groundwater, wetlands, and biodiversity;
- An active spill prevention and management program;
- Support for regional air shed monitoring for emissions and their deposition; and
- An internal environmental management system for conformance audit and inspection programs of operating facilities.

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and have been discounted using a weighted average discount rate of 4.9% (2024 – 4.8%; 2023 – 5.2%). For 2025, the Company's capital expenditures included \$771 million for abandonment expenditures (2024 – \$646 million; 2023 – \$509 million). The Company's estimated discounted ARO at December 31, 2025 was as follows:

(\$ millions)	<b>2025</b>	2024
Exploration and Production		
North America	<b>\$ 4,937</b>	\$ 4,783
North Sea	<b>2,629</b>	1,724
Offshore Africa	<b>275</b>	197
Oil Sands Mining and Upgrading	<b>1,901</b>	1,902
Midstream and Refining	<b>1</b>	1
	<b>\$ 9,743</b>	\$ 8,607

The discounted ARO was based on estimates of future costs to abandon and restore wells, production facilities, mine sites, upgrading facilities and tailings, and offshore production platforms.

Factors that affect costs include number of wells drilled, well depth, facility size and the specific environmental legislation. The estimated future costs are based on estimates of current costs in accordance with present legislation, industry operating practice as well as the expected work scope and the timing of abandonment.

The Alberta Energy Regulator ("AER") established a Liability Management Framework, as part of its life-cycle management of oil and natural gas wells, facilities and pipelines, which imposes mandatory annual minimum spend requirements on licensees for the closure of inactive wells and related infrastructure. Under the framework, the AER assigns a licensee an annual minimum spend requirement for reclamation and abandonment activities to be completed based on a licensee's proportionate share of the provincial inventory of inactive wells and related infrastructure, among other factors. In Alberta, the mandatory minimum spend requirements are reviewed annually and have increased from 4% in 2022 to the current rate of 6.2% in 2025. The Government of Saskatchewan has a similar program in place (the Inactive Liability Reduction Program), which had a 6% minimum spend requirement in 2025. In British Columbia, the Dormancy and Shutdown Regulations also set out mandatory targets for decommissioning and restoring inactive wells and facilities. In addition to minimum spend requirements for abandonment and reclamation, each of the provincial regulators have the ability to require licensees to post financial security to secure a licensee's abandonment and reclamation obligations.

## **GREENHOUSE GAS AND OTHER EMISSIONS**

The Company, through industry associations, is working with Canadian legislators and regulators as they develop and implement laws and regulations to properly reflect a balanced approach to sustainable development, such as programs to support industry investments in environmental performance improvement and emissions reduction. The Company continues to develop strategies that will enable it to deal with the risks and opportunities associated with new and existing GHG and air emissions policies. In addition, the Company is working with relevant parties to ensure that new and existing policies encourage technological innovation, energy efficiency, and targeted research and development while not impacting competitiveness.

Governments in jurisdictions where the Company operates have developed GHG regulations as part of their provincial, federal and international climate change commitments. The Company continuously monitors developments in the GHG regulatory environment in applicable jurisdictions to assess the cost impact of new and existing regulations on current and future operations and proposed projects under consideration.

### **Federal Carbon Policy and GHG Emissions Regulation**

The federal government ratified the Paris Agreement, which included a commitment to reduce Canada's GHG emissions by 40 – 45% from 2005 levels by 2030. In December 2024, the federal government updated its commitment to extend the timing to achieve the national GHG emission reduction target to 2035. The federal regulations supporting the Paris Agreement mandate that the federal carbon price increase in annual increments of \$15/tonne after 2022 to \$170 per tonne by 2030. The federal Clean Fuel Regulations ("CFR"), which took effect on July 1, 2023, require reductions in the carbon intensity of gasoline and diesel fuels produced or sold in Canada. The federal Clean Electricity Regulations ("CER") came into effect on January 1, 2025, and establishes GHG emission limits for almost all fossil fuel-powered electricity generation units, beginning in 2035.

In addition to existing federal GHG regulations and the CFR, the federal government published draft regulations in 2024 that propose to cap emissions from the oil and gas sector through a national cap-and-trade system. This has not yet been implemented and is dependent on final agreements negotiated as part of the MOU (see below for further discussion). In 2025, new federal regulations were also released intended to control the release of volatile organic compounds ("VOCs") from petroleum refineries and upgraders; truck, rail, marine, and pipeline terminals; petrochemical facilities; bulk fuel facilities; and steel mills.

In November 2025, the federal and Alberta governments entered into the MOU which is intended to increase western Canada's energy production and establish Canada as an energy leader while reducing GHG emissions through innovative technologies and infrastructure programs. The MOU included the following:

- The federal government agreed not to implement an oil and gas emissions cap, contingent on the province of Alberta meeting certain commitments, one of which is related to the development of carbon capture infrastructure;
- The application of the CER in Alberta was suspended pending the finalization of a new carbon pricing agreement to be administered through Alberta's Technology Innovation and Emissions Reduction ("TIER") Regulation program, the details of which are to be negotiated by the parties on or before April 1, 2026; and
- A commitment by the parties to work collaboratively to design and implement a globally competitive, long-term carbon pricing scheme, carbon levy recycling protocols, and sector-specific stringency factors for large emitters in both the oil and gas and electricity sectors through Alberta's TIER system. Under this proposal, the TIER system will ramp up to a minimum effective credit price of \$130/tonne. The parties are anticipated to conclude an agreement on industrial carbon pricing on or before April 1, 2026 in furtherance of this agreement.

Although the MOU appears supportive of Canada's energy sector, there are no assurances that the parties will reach final agreement on all of the necessary elements required to enable the MOU framework or that the environmental laws and regulations negotiated as part of the MOU will have a favourable impact on either the oil and gas industry in Alberta or the Company and may ultimately have a material adverse effect on the Company's business, financial condition and operations.

## Provincial GHG Policy and Regulation

Industrial carbon pricing regulatory systems in all provinces are subject to periodic review by the federal government to assess the adequacy of the provincial systems against the federal Greenhouse Gas Pollution Pricing Act. To the extent a province's carbon pricing system does not meet the federal stringency requirements, the federal backstop regulations apply.

**Alberta:** In Alberta, the TIER sets the carbon pricing framework that applies to the Company's facilities with emissions greater than 100,000 t CO<sub>2</sub>e/year, and certain facilities opted into the TIER system by the Company. In 2025, the carbon price in Alberta for emissions above the TIER regulated limits was \$95/tonne. In May 2025, the Alberta government indefinitely capped the carbon price at \$95/tonne, which may be subject to change following finalization of a new carbon pricing agreement with the federal government on or before April 1, 2026 (as stipulated in the MOU). Emissions from the non-operated Scotford Upgrader and the North West Redwater bitumen upgrader and refinery are also subject to TIER.

**British Columbia:** In 2025, the industrial carbon price in British Columbia under the province's output based price system was \$95/tonne and increases by \$15/tonne CO<sub>2</sub>e annually until it reaches \$170/tonne of CO<sub>2</sub>e in 2030, in alignment with the federal carbon pricing schedule. In 2023, British Columbia announced its intention to implement a Net-Zero New Industry policy as well as an emissions cap for the oil and gas industry. This cap is intended to ensure that the province meets its emissions reduction target of 33-38% below 2007 emissions levels by 2030. In 2024, British Columbia announced that it would be introducing regulatory measures to backstop the federal carbon emissions cap, which were to apply in the event of gaps between federal and provincial targets and in the event that the federal emissions cap is not implemented or cancelled.

**Saskatchewan:** As part of its Prairie Resilience Plan, in 2018, the Saskatchewan government enacted the Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations, that apply to facilities emitting more than 25 kilotonnes of CO<sub>2</sub>e annually. This regulation required the Company's North Tangleflags in situ heavy crude oil facility and the Senlac in situ heavy crude oil facility to meet reduction targets for GHG emissions commencing in 2020. This regulation also enables facilities that emit less than 25 kilotonnes of CO<sub>2</sub>e annually to aggregate and opt-in to the Saskatchewan regulatory system as an alternative to the federal fuel charge. In April 2025, the province of Saskatchewan paused the application and collection of industrial carbon taxes. Since this would result in Saskatchewan not meeting the federal stringency requirement, the province may be subject to the federal backstop regulation if applied by the federal government in the future.

**Manitoba:** In the absence of provincial regulations for carbon pricing and GHG emissions, the federal output-based pricing system and carbon pricing schedule applies to Manitoba facilities with emissions greater than or equal to 50 kilotonnes of CO<sub>2</sub>e annually. Facilities with emissions equal to or greater than 10 kilotonnes CO<sub>2</sub>e annually can voluntarily opt-in to the system.

## Methane Emissions Reduction Regulations

The federal government's methane regulation which came into effect on January 1, 2020 applies nationally unless provinces reach equivalency agreements with the federal government. The federal government originally had a commitment to reduce methane emissions from the oil and gas sector by 40-45% from the 2012 levels by 2025. In 2021, the federal government set a target to further reduce methane emissions to achieve at least a 75% reduction below 2012 levels by 2030. The provinces of British Columbia, Alberta and Saskatchewan have equivalency agreements in place with the federal government that allow the applicable provincial methane regulations to govern in these three western provinces. The federal methane regulation continues to apply in the province of Manitoba. Pursuant to the MOU entered into by the federal government and the government of Alberta in November 2025, the parties intend to enter into a new methane equivalency agreement on or before April 1, 2026. Once concluded, this new equivalency agreement will extend the target date to achieve the mandated 75% methane emissions reduction (relative to 2014 levels) to 2035. In December 2025, the final methane regulation ("Enhanced Methane Regulations") was enacted by the federal government, with phase-in of the regulatory requirements beginning January 1, 2028.

## United Kingdom GHG Emissions Regulation

GHG emissions from the Company's UK operations are regulated under the UK Emissions Trading Scheme ("ETS") which was launched on January 1, 2021 and replaced the UK's participation in a comparable European Union ("EU") system. The UK scheme is aligned with the EU ETS rules and applies to energy intensive industries, the power generation sector and aviation.

# Accounting Policies and Standards

## 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 this MD&A and the audited consolidated financial statements for the year ended December 31, 2025.

### A) Depletion, Depreciation and Amortization and Impairment

Exploration and evaluation ("E&E") costs relating to activities to explore and evaluate crude oil and natural gas properties are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E assets are carried forward until technical feasibility and commercial viability of extracting a mineral resource is determined. Technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. The judgements associated with the estimation of proved reserves are described below in 'Crude Oil and Natural Gas Reserves'.

An alternative acceptable accounting method for E&E costs under IFRS 6 "Exploration for and Evaluation of Mineral Resources" is to charge exploratory dry holes and geological and geophysical exploration costs incurred after having obtained the legal rights to explore an area against net earnings in the period incurred rather than capitalizing to E&E assets.

E&E assets are tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. The determination of the fair value of CGUs requires the use of assumptions and estimates including future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, discount rates, income taxes, and the potential impact of climate related matters and in accordance with related government regulations. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and impairment provisions. Crude oil and natural gas properties in the Exploration and Production segments are depleted using the unit-of-production method over proved reserves, except for major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future estimated development expenditures required to develop proved reserves. Estimates of proved reserves have a significant impact on net earnings, as they are a key input to the calculation of depletion expense.

The Company assesses property, plant and equipment for impairment discounted at rates currently ranging from 10% to 12% whenever events or changes in circumstances indicate that the carrying value of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low commodity prices for an extended period, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs a recoverability assessment related to the specific assets at the CGU level.

### B) Crude Oil and Natural Gas Reserves

Reserves estimates, evaluated by the Company's Independent Qualified Reserves Evaluators, are based on estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations, and judgements, including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information. Reserves estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization and for determining potential asset impairment. For example, a revision to the proved reserves estimates would result in a higher or lower depletion, depreciation and amortization charge to net earnings. Downward revisions to reserves estimates may also result in an impairment of E&E and property, plant and equipment carrying amounts.

### C) Asset Retirement Obligations

The Company is required to recognize a liability for ARO associated with its property, plant and equipment, including property, plant and equipment for which underlying reserves have been de-booked, and the carrying value of the asset has been fully depleted. An ARO liability associated with the retirement of a tangible long-lived asset is recognized to the extent of a legal obligation resulting from an existing or enacted law, statute, ordinance or written or oral contract, or by legal construction of a contract under the doctrine of promissory estoppel. The ARO is based on estimated costs, taking into account the anticipated method and extent of restoration consistent with legal requirements, technological advances and the possible use of the site. Since these estimates are specific to the sites involved, there are many individual assumptions underlying the Company's total

ARO amount, including the potential impact of climate related matters and in accordance with related government regulations. These individual assumptions may be subject to change.

The estimated present values of ARO related to long-term assets are recognized as a liability in the period in which they are incurred. The provision for the ARO is estimated by discounting the expected future cash flows to settle the ARO at the Company's weighted average credit-adjusted risk-free interest rate, which is currently 4.9%. Subsequent to initial measurement, the ARO is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense whereas changes in discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Changes in estimates would impact accretion and depletion expense. In addition, differences between actual and estimated costs to settle the ARO, timing of cash flows to settle the obligation and future inflation rates may result in gains or losses on the final settlement of the ARO.

#### **D) Income Taxes**

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted that are expected to apply when the asset or liability is recovered. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

#### **E) Risk Management Activities**

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable quoted market inputs including crude oil and natural gas forward benchmark commodity prices and volatility, Canadian and United States forward interest rate yield curves, Canadian and United States foreign exchange rates and other volatility factors discounted to present value as appropriate. The carrying amount of a risk management liability is adjusted for the Company's own credit risk. The resulting fair value estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction and these differences may be material.

#### **F) Purchase Price Allocations**

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions, and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, derived from the present value of estimated future cash flows from the assets, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

The Company has made various assumptions in determining the fair values of acquired assets and liabilities. The most significant assumptions and judgements relate to the estimation of the fair value of crude oil and natural gas properties. To determine the fair value of these properties, the Company estimates crude oil and natural gas reserves. Reserves estimates are based on the work performed by the Company's internal engineers and outside consultants. The judgements associated with these estimated reserves are described above in 'Crude Oil and Natural Gas Reserves'. Estimates of future prices are based on prices derived from price forecasts among industry analysts and internal assessments. The Company applies estimated future prices to the estimated reserves quantities acquired, and estimates future production and development costs, to arrive at estimated future net revenues for the properties acquired.

#### **G) Share-Based Compensation**

The Company has made various assumptions in estimating the fair values of stock options granted including expected volatility, expected exercise timing, and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

#### **H) Leases**

Purchase, extension, and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgement to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options

may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

## **I) Government Grants**

The Company receives or is eligible for government grants including emissions credits. Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta TIER regulation are initially recorded at fair value as determined by the prescribed Alberta TIER fund compliance rates in effect at the time the credits are recognized.

## **Control Environment**

The Company's management, including the President and the Chief Financial Officer, evaluated the effectiveness of disclosure controls and procedures as at December 31, 2025, and concluded that disclosure controls and procedures are effective to ensure that information required to be disclosed by the Company in its annual filings and other reports filed with securities regulatory authorities in Canada and the United States is recorded, processed, summarized, and reported within the time periods specified and such information is accumulated and communicated to the Company's management to allow timely decisions regarding required disclosures.

The Company's management, including the President and the Chief Financial Officer, also evaluated the effectiveness of internal control over financial reporting as at December 31, 2025, and concluded that internal control over financial reporting is effective. Further, there were no changes in the Company's internal control over financial reporting during 2025 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

While the Company's management believes that the Company's disclosure controls and procedures and internal control over financial reporting provide a reasonable level of assurance they are effective, they recognize that all control systems have inherent limitations. Because of its inherent limitations, the Company's control systems may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

## 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.

(\$ millions)		2025	2024	2023
Net earnings	\$	10,820	\$ 6,106	\$ 8,233
Share-based compensation, net of tax <sup>(1)</sup>		166	257	474
Unrealized risk management loss, net of tax <sup>(2)</sup>		55	10	7
Unrealized foreign exchange (gain) loss, net of tax <sup>(3)</sup>		(870)	888	(260)
Realized foreign exchange loss on financing activities, net of tax <sup>(4)</sup>		54	135	—
Gain from investment, net of tax <sup>(5)</sup>		—	(50)	(34)
Gain on acquisitions, disposition, and remeasurement, net of tax <sup>(6) (7)</sup>		(3,925)	—	—
Recoverability charges, net of tax <sup>(8) (9)</sup>		1,144	68	113
Non-operating items, net of tax		(3,376)	1,308	300
Adjusted net earnings from operations	\$	7,444	\$ 7,414	\$ 8,533

(1) Share-based compensation includes costs incurred under the Company's Stock Option Plan and PSU Plan. The fair value of the share-based compensation is recognized as a liability on the Company's balance sheets, and periodic changes in the fair value are recognized in net earnings. Pre-tax share-based compensation for 2025 was an expense of \$180 million (2024 – \$279 million expense; 2023 – \$491 million expense).

(2) Derivative financial instruments are recognized at fair value on the Company's balance sheets, with changes in the fair value of non-designated hedges recognized in net earnings. The amounts ultimately realized may be materially different than those amounts reflected in the Company's audited consolidated financial statements due to changes in prices of the underlying items hedged, primarily natural gas and foreign exchange. The pre-tax unrealized risk management loss for 2025 was \$71 million (2024 – \$9 million loss; 2023 – \$12 million loss).

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

(4) Realized foreign exchange 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 losses are the same.

(5) The Company's investments have been accounted for at fair value through profit and loss and are measured each period with gains and losses recognized in net earnings. During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. for \$25.65 per common share with net proceeds at close, after fees and expenses, of \$575 million. There is a \$nil net tax impact on the sale as the Company has sufficient capital losses to offset the capital gain on the sale.

(6) During 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.

(7) During 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 'Financial and Operational Highlights' section of this MD&A.

(8) During 2025, the Company recognized pre-tax non-cash recoverability charges of \$1,462 million (\$836 million after-tax) (2024 – \$160 million (\$21 million after-tax); 2023 – \$436 million (\$113 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.

(9) During 2025, the Company recognized pre-tax non-cash recoverability charges of \$315 million (\$308 million after-tax) (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.

(\$ millions)		2025		2024		2023
Cash flows from operating activities	\$	15,106	\$	13,386	\$	12,353
Net change in non-cash working capital		(672)		743		2,417
Abandonment expenditures		771		646		509
Movements in other long-term assets <sup>(1)</sup>		255		84		(5)
Adjusted funds flow	\$	15,460	\$	14,859	\$	15,274

(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 16 to the Company's audited consolidated 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.

## ABANDONMENT EXPENDITURES, NET

Abandonment expenditures, net, is a non-GAAP financial measure that represents the abandonment expenditures to settle asset retirement obligations as reflected in the Company's historical annual capital budgets. Abandonment expenditures, net is calculated as abandonment expenditures, as presented in the Company's audited consolidated statements of cash flows, adjusted for the impact of government grant income under the provincial well-site rehabilitation programs. Beginning in 2023, the Company no longer receives government grant income under these programs and as a result, the measure no longer differs from the most directly comparable GAAP measure and is not reported in this MD&A.

## 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', 'Per Unit Results – Exploration and Production', and 'Per Unit Results – Oil Sands Mining and Upgrading' sections 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 21 to the Company's audited consolidated financial statements.

During 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 audited consolidated 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 21 to the Company's audited consolidated financial statements. The Company considers realized price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit the Company obtained on the market for its crude oil and NGLs sales volumes and BOE sales volumes.

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

(\$ millions, except bbl/d and \$/bbl)	2025	2024	2023
<b>Crude oil and NGLs (bbl/d)</b>			
North America	<b>570,262</b>	504,339	497,604
International			
North Sea	<b>9,146</b>	11,455	10,749
Offshore Africa	<b>4,520</b>	11,198	14,882
Total International	<b>13,666</b>	22,653	25,631
Total sales volumes	<b>583,928</b>	526,992	523,235
Crude oil and NGLs sales <sup>(1)</sup>	<b>\$ 19,591</b>	\$ 19,641	\$ 18,387
Less: Blending and feedstock costs <sup>(2)</sup>	<b>4,344</b>	4,643	4,568
Realized crude oil and NGLs sales	<b>\$ 15,247</b>	\$ 14,998	\$ 13,819
Realized price (\$/bbl)	<b>\$ 71.54</b>	\$ 77.76	\$ 72.36

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

(\$ millions, except BOE/d and \$/BOE)	2025	2024	2023
<b>Barrels of oil equivalent (BOE/d)</b>			
North America	<b>993,279</b>	860,367	854,138
International			
North Sea	<b>9,656</b>	11,791	11,034
Offshore Africa	<b>5,575</b>	12,728	16,638
Total International	<b>15,231</b>	24,519	27,672
Total sales volumes	<b>1,008,510</b>	884,886	881,810
Barrels of oil equivalent sales <sup>(1)</sup>	<b>\$ 21,921</b>	\$ 21,105	\$ 20,820
Less: Blending and feedstock costs <sup>(2)</sup>	<b>4,344</b>	4,643	4,568
Less: Sulphur (income) expense	<b>(85)</b>	3	(14)
Realized barrels of oil equivalent sales	<b>\$ 17,662</b>	\$ 16,459	\$ 16,266
Realized price (\$/BOE)	<b>\$ 47.98</b>	\$ 50.82	\$ 50.54

(1) Barrels of oil equivalent sales includes crude oil and NGLs sales and natural gas sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated 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 21 to the Company's audited consolidated financial statements. The Company considers the realized crude oil and NGLs price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its crude oil and NGLs sales volumes.

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

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

(\$ millions, except \$/bbl and royalty rates)	2025		2024		2023	
Crude oil and NGLs sales <sup>(1)</sup>	\$	<b>19,102</b>	\$	18,740	\$	17,375
Less: Blending and feedstock costs <sup>(2)</sup>		<b>4,344</b>		4,643		4,568
Realized crude oil and NGLs sales	\$	<b>14,758</b>	\$	14,097	\$	12,807
Realized crude oil and NGLs prices (\$/bbl)	\$	<b>70.90</b>	\$	76.37	\$	70.51
Crude oil and NGLs royalties <sup>(3)</sup>	\$	<b>2,450</b>	\$	2,842	\$	2,340
Crude oil and NGLs royalty rates		<b>17%</b>		20%		18%

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated financial statements.

(3) Item is a component of royalties in note 21 to the Company's audited consolidated 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 21 to the Company's audited consolidated financial statements. The Company considers realized SCO sales price a key measure in evaluating its performance, as it demonstrates the realized pricing per unit that the Company obtained on the market for its SCO sales volumes.

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

(\$ millions, except for bbl/d and \$/bbl)	2025		2024		2023	
SCO sales volumes (bbl/d)		<b>567,335</b>		468,280		449,282
Crude oil and NGLs sales <sup>(1)</sup>	\$	<b>20,112</b>	\$	19,263	\$	18,661
Less: Blending and feedstock costs <sup>(2)</sup>		<b>2,218</b>		2,462		2,253
Realized SCO sales	\$	<b>17,894</b>	\$	16,801	\$	16,408
Realized SCO sales price (\$/bbl)	\$	<b>86.41</b>	\$	98.03	\$	100.06

(1) Crude oil and NGLs sales in note 21 to the Company's audited consolidated financial statements.

(2) Blending and feedstock costs in note 21 to the Company's audited consolidated 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.

(\$ millions)	2025	2024	2023
Cash flows used in investing activities	\$ 6,687	\$ 14,095	\$ 4,858
Working capital acquired from Chevron	—	(115)	—
Net proceeds from investment	—	575	—
Net change in non-cash working capital	(108)	(124)	51
Net capital expenditures	6,579	14,431	4,909
Abandonment expenditures	771	646	509
Capital and abandonment expenditures	\$ 7,350	\$ 15,077	\$ 5,418

## LIQUIDITY

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

(\$ millions)	2025	2024	2023
Undrawn bank credit facilities	\$ 5,668	\$ 4,562	\$ 5,450
Cash and cash equivalents	673	131	877
Investments <sup>(1)</sup>	—	—	525
Liquidity	\$ 6,341	\$ 4,693	\$ 6,852

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

## LONG-TERM DEBT, NET

Long-term debt, net, is a capital management measure that represents long-term debt, including the current portion of long-term debt, less cash and cash equivalents, as disclosed in note 15 to the Company's audited consolidated financial statements. A reconciliation of the Company's long-term debt, net is presented below.

(\$ millions)	2025	2024	2023
Long-term debt	\$ 16,617	\$ 18,819	\$ 10,799
Less: Cash and cash equivalents	673	131	877
Long-term debt, net	\$ 15,944	\$ 18,688	\$ 9,922

## DEBT TO BOOK CAPITALIZATION

Debt to book capitalization is a capital management measure intended to enable financial statement users to evaluate the Company's capital structure, as disclosed in note 15 to the Company's audited consolidated 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)	2025	2024	2023
Interest adjusted after-tax return:			
Net earnings, 12 months trailing <sup>(1)</sup>	\$ 10,820	\$ 6,106	\$ 8,233
Interest and other financing expense, net of tax, 12 months trailing <sup>(2)</sup>	640	454	490
Interest adjusted after-tax return	\$ 11,460	\$ 6,560	\$ 8,723
12 months average current portion long-term debt <sup>(3)</sup>	\$ 1,293	\$ 1,525	\$ 1,259
12 months average long-term debt <sup>(3)</sup>	16,149	10,642	10,354
12 months average common shareholders' equity <sup>(3)</sup>	41,208	39,635	38,974
12 months average capital employed	\$ 58,650	\$ 51,802	\$ 50,587
After-tax return on average capital employed	20%	13%	17%

(1) Net earnings, 12 months trailing for 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 6 to the Company's audited consolidated 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.

## Other

### SENSITIVITY ANALYSIS

The following table is indicative of the annualized sensitivities of cash flows from operating activities and net earnings due to changes in certain key variables. The analysis is based on business conditions and sales volumes during the fourth quarter of 2025, excluding mark-to-market gains (losses) on risk management activities and is not necessarily indicative of future results. Each separate line item in the sensitivity analysis shows the effect of a change in that variable only with all other variables being held constant.

	Cash flows from Operating Activities (\$ millions)	Cash flows from Operating Activities (per common share, basic)	Net earnings (\$ millions)	Net earnings (per common share, basic)
<b>Price changes</b>				
Crude oil – WTI US\$1.00/bbl	\$ 409	\$ 0.20	\$ 409	\$ 0.20
Natural gas – AECO C\$0.10/Mcf <sup>(1)</sup>				
Excluding financial derivatives	\$ 52	\$ 0.02	\$ 52	\$ 0.02
Including financial derivatives	\$ 51	\$ 0.02	\$ 51	\$ 0.02
<b>Volume changes</b>				
Crude oil – 10,000 bbl/d	\$ 136	\$ 0.07	\$ 114	\$ 0.05
Natural gas – 10 MMcf/d	\$ 3	\$ —	\$ (3)	\$ —
<b>Foreign currency rate change</b>				
\$0.01 change in US\$ <sup>(1)</sup>				
Including financial derivatives	\$ 267	\$ 0.13	\$ 78	\$ 0.04
<b>Interest rate change – 1%</b>	\$ 33	\$ 0.02	\$ 33	\$ 0.02

(1) For details of financial instruments in place, refer to note 18 to the Company's audited consolidated financial statements.

## DAILY PRODUCTION BY SEGMENT, BEFORE ROYALTIES

	Q1	Q2	Q3	Q4	2025	2024	2023
<b>Crude oil and NGLs</b> (bbl/d)							
North America – Exploration and Production	561,238	545,811	584,625	585,497	569,401	509,288	496,100
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	595,116	463,808	581,136	619,901	565,102	472,245	451,339
International							
North Sea	11,507	7,761	7,045	7,618	8,468	11,536	12,639
Offshore Africa	5,943	1,769	2,798	2,348	3,204	12,534	13,452
Total International	17,450	9,530	9,843	9,966	11,672	24,070	26,091
Total Crude oil and NGLs	1,173,804	1,019,149	1,175,604	1,215,364	1,146,175	1,005,603	973,530
<b>Natural gas</b> (MMcf/d) <sup>(2)</sup>							
North America	2,436	2,398	2,658	2,657	2,538	2,136	2,139
International							
North Sea	4	3	2	3	3	2	2
Offshore Africa	11	6	8	—	6	9	10
Total International	15	9	10	3	9	11	12
Total Natural gas	2,451	2,407	2,668	2,660	2,547	2,147	2,151
<b>Barrels of oil equivalent</b> (BOE/d)							
North America – Exploration and Production	967,245	945,451	1,027,598	1,028,326	992,419	865,314	852,633
North America – Oil Sands Mining and Upgrading <sup>(1)</sup>	595,116	463,808	581,136	619,901	565,102	472,245	451,339
International							
North Sea	12,241	8,245	7,381	8,106	8,978	11,873	12,925
Offshore Africa	7,746	2,854	4,146	2,348	4,258	14,064	15,208
Total International	19,987	11,099	11,527	10,454	13,236	25,937	28,133
Total Barrels of oil equivalent	1,582,348	1,420,358	1,620,261	1,658,681	1,570,757	1,363,496	1,332,105

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

(2) Natural gas production volumes approximate sales volumes.

## PER UNIT RESULTS – EXPLORATION AND PRODUCTION

	Q1	Q2	Q3	Q4	2025	2024	2023
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>							
Realized price <sup>(2)</sup>	\$ 79.85	\$ 69.58	\$ 72.57	\$ 64.42	\$ 71.54	\$ 77.76	\$ 72.36
Transportation <sup>(3)</sup>	6.40	7.65	6.93	7.14	7.02	5.50	4.23
Realized price, net of transportation <sup>(2)</sup>	73.45	61.93	65.64	57.28	64.52	72.26	68.13
Royalties <sup>(4)</sup>	14.36	9.20	13.10	9.46	11.53	14.85	12.55
Production expense <sup>(5)</sup>	15.74	14.03	13.18	14.35	14.33	14.72	16.12
Netback <sup>(2)</sup>	\$ 43.35	\$ 38.70	\$ 39.36	\$ 33.47	\$ 38.66	\$ 42.69	\$ 39.46
<b>Natural gas (\$/Mcf) <sup>(1)</sup></b>							
Realized price <sup>(6)</sup>	\$ 3.13	\$ 2.58	\$ 1.49	\$ 2.89	\$ 2.51	\$ 1.86	\$ 3.10
Transportation <sup>(3)</sup>	0.63	0.59	0.57	0.56	0.59	0.62	0.56
Realized price, net of transportation	2.50	1.99	0.92	2.33	1.92	1.24	2.54
Royalties <sup>(4)</sup>	0.11	0.08	0.02	0.09	0.08	0.05	0.13
Production expense <sup>(5)</sup>	1.20	1.11	1.16	1.10	1.14	1.22	1.30
Netback <sup>(7)</sup>	\$ 1.19	\$ 0.80	\$ (0.26)	\$ 1.14	\$ 0.70	\$ (0.03)	\$ 1.11
<b>Barrels of oil equivalent (\$/BOE) <sup>(1)</sup></b>							
Realized price <sup>(2)</sup>	\$ 54.95	\$ 47.17	\$ 45.31	\$ 44.85	\$ 47.98	\$ 50.82	\$ 50.54
Transportation <sup>(3)</sup>	5.34	5.94	5.38	5.56	5.54	4.78	3.88
Realized price, net of transportation <sup>(2)</sup>	49.61	41.23	39.93	39.29	42.44	46.04	46.66
Royalties <sup>(4)</sup>	8.76	5.58	7.53	5.73	6.90	8.96	7.77
Production expense <sup>(5)</sup>	12.23	10.95	10.50	11.08	11.18	11.73	12.74
Netback <sup>(2)</sup>	\$ 28.62	\$ 24.70	\$ 21.90	\$ 22.48	\$ 24.36	\$ 25.35	\$ 26.15

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

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

(3) Calculated as 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.

## PER UNIT RESULTS – OIL SANDS MINING AND UPGRADING

	Q1	Q2	Q3	Q4	2025	2024	2023
<b>Crude oil and NGLs (\$/bbl) <sup>(1)</sup></b>							
Realized SCO sales price <sup>(2)</sup>	\$ 95.52	\$ 87.22	\$ 87.85	\$ 75.90	\$ 86.41	\$ 98.03	\$ 100.06
Bitumen royalties <sup>(3)</sup>	18.22	11.59	15.80	9.54	13.84	17.23	14.43
Transportation <sup>(4)</sup>	3.21	3.73	3.86	2.56	3.31	2.91	1.89
Production expense <sup>(5)</sup>	21.88	26.53	21.29	21.84	22.66	22.88	24.32
Netback <sup>(2)</sup>	\$ 52.21	\$ 45.37	\$ 46.90	\$ 41.96	\$ 46.60	\$ 55.01	\$ 59.42

(1) For SCO sales volumes, refer to the 'Non-GAAP and Other Financial Measures' section of this MD&A.

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

(3) Calculated as royalties divided by sales volumes.

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

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

## TRADING AND SHARE STATISTICS

	Q1	Q2	Q3	Q4	2025	2024
<b>TSX – C\$</b>						
Trading volume (thousands)	809,387	1,007,979	998,028	1,030,966	3,846,360	3,025,819
Share Price (\$/share)						
High	\$ 48.26	\$ 46.92	\$ 46.12	\$ 49.20	\$ 49.20	\$ 56.50
Low	\$ 37.11	\$ 34.92	\$ 40.62	\$ 41.67	\$ 34.92	\$ 40.02
Close	\$ 44.28	\$ 42.80	\$ 44.50	\$ 46.49	\$ 46.49	\$ 44.38
Market capitalization as at December 31, (\$ millions)					\$ 96,773	\$ 93,331
Shares outstanding (thousands)					2,081,578	2,102,996
<b>NYSE – US\$</b>						
Trading volume (thousands)	438,860	412,850	381,546	435,083	1,668,339	1,310,294
Share Price (\$/share)						
High	\$ 33.51	\$ 34.33	\$ 33.24	\$ 35.12	\$ 35.12	\$ 41.29
Low	\$ 25.62	\$ 24.65	\$ 29.30	\$ 29.69	\$ 24.65	\$ 29.23
Close	\$ 30.80	\$ 31.40	\$ 31.96	\$ 33.85	\$ 33.85	\$ 30.87
Market capitalization as at December 31, (\$ millions)					\$ 70,461	\$ 64,919
Shares outstanding (thousands)					2,081,578	2,102,996

# Consolidated Financial Statements

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# Management's Report

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The accompanying consolidated financial statements of Canadian Natural Resources Limited (the "Company") and all other information contained elsewhere in this Annual Report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies described in the accompanying notes. Where necessary, management has made informed judgements and estimates in accounting for transactions that were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards") as appropriate in the circumstances. The financial information presented elsewhere in the Annual Report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized and recorded, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinions on the following:

- the Company's consolidated financial statements as at and for the year ended December 31, 2025; and
- the effectiveness of the Company's internal control over financial reporting as at December 31, 2025.

Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board, which is comprised entirely of independent directors. The Audit Committee meets with management and the independent auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.



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**SCOTT G. STAUTH**

President



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**VICTOR C. DAREL, CPA**

Chief Financial Officer

Calgary, Alberta, Canada

March 4, 2026

# Management's Assessment of Internal Control over Financial Reporting

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Management of Canadian Natural Resources Limited (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting for the Company as defined in Rules 13a-15(f) and 15d-15(f) under the United States Securities Exchange Act of 1934, as amended.

Management, including the Company's President and the Company's Chief Financial Officer, performed an assessment of the Company's internal control over financial reporting based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on the assessment, management has concluded that the Company's internal control over financial reporting was effective as at December 31, 2025. Management recognizes that all internal control systems have inherent limitations. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP, an independent firm of Chartered Professional Accountants, has provided an opinion on the Company's internal control over financial reporting as at December 31, 2025, as stated in their accompanying Report of Independent Registered Public Accounting Firm.



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**SCOTT G. STAUTH**

President



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**VICTOR C. DAREL, CPA**

Chief Financial Officer

Calgary, Alberta, Canada

March 4, 2026

# Report of Independent Registered Public Accounting Firm

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## To the Board of Directors and Shareholders of Canadian Natural Resources Limited

### Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Canadian Natural Resources Limited and its subsidiaries (the "Company") as of December 31, 2025 and 2024, and the related consolidated statements of earnings, of comprehensive income, of changes in equity and of cash flows for each of the three years in the period ended December 31, 2025, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2025 and 2024, and its financial performance and its cash flows for each of the three years in the period ended December 31, 2025 in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2025, based on criteria established in Internal Control – Integrated Framework (2013) issued by the COSO.

### Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Assessment of Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

### Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

## Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the Audit Committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

### **Determination of the fair value of the interests in the Athabasca Oil Sands Project ("AOSP") Mines in the AOSP Asset Swap Transaction**

As described in Notes 1, 3 and 6 to the Company's consolidated financial statements, on November 1, 2025, the Company completed the AOSP asset swap transaction. The AOSP assets include the AOSP mines, the Scotford Upgrader ("Scotford") and the Quest Carbon Capture and Storage facility ("Quest"), all of which are presented as property, plant and equipment. As a result of the transaction, the Company acquired the remaining 10% interest in the AOSP mines and associated reserves, resulting in the Company owning a 100% interest in such assets. The transaction was accounted for as a business combination achieved in stages using the acquisition method of accounting as a result of obtaining control of the AOSP mines. The Company was deemed to have disposed of its pre-existing interests in the AOSP mines and re-acquired them at fair value, as determined in accordance with IFRS Accounting Standards, at the acquisition date, with any gains on remeasurement recognized in net earnings. Management determined the acquisition date fair value of the 100% interest in the AOSP mines, using an estimated 18% discount rate based on comparable market transactions, was \$15,488 million, and recognized a \$4,508 million non-cash gain on the remeasurement of its pre-existing interests in the AOSP mines as a result. Management determined the fair value of the interests in the AOSP mines by using a discounted estimate of future cash flows approach which required the use of estimates and judgments by management, including developing key assumptions related to discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. Management utilizes third party specialists, specifically independent qualified reserves evaluators ("Management's Specialists") to evaluate its estimated quantity of reserves.

The principal considerations for our determination that performing procedures relating to the determination of the fair value of the interests in the AOSP mines in the AOSP Asset Swap Transaction is a critical audit matter are the significant judgments required by management, including the use of Management's Specialists, when determining the fair value of the interests in the AOSP mines. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures and evaluating evidence obtained related to the key assumptions used in developing the fair value, at the acquisition date, of the interests in the AOSP mines, including discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. The audit effort also involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's determination of the fair value, at the acquisition date, of the interests in the AOSP mines. These procedures also included, among others, testing management's process for determining the fair value, at the acquisition date, of the interests in the AOSP mines, including (i) evaluating the appropriateness of the method used by management in making the estimate, (ii) testing the completeness and accuracy of underlying data used in management's determination of the fair value, and (iii) evaluating the reasonableness of key assumptions used by management related to discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest. Evaluating the key assumptions related to estimated future prices, expected future rates of production, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest involved assessing whether they were reasonable considering the past performance of the AOSP mines, external market and industry data and whether they were consistent with evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the present value of estimated future cash flows from the AOSP mines and the reasonableness of the discount rate. The work of Management's Specialists was used in performing procedures to evaluate the reasonableness of the estimated quantity of reserves. As a basis for using this work, Management's Specialists' qualifications were understood and the Company's relationship with Management's Specialists was assessed. The procedures performed also included evaluating the methods and assumptions used by Management's Specialists, testing the completeness and accuracy of the data used by Management's Specialists, and evaluating Management's Specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable.

### **The Impact of Crude Oil and Natural Gas Reserves on Property, Plant and Equipment Assets in the North America Exploration and Production Segment**

As described in Notes 1, 3 and 6 to the Company's consolidated financial statements, the property, plant and equipment ("PP&E") balance in the North America Exploration and Production segment was \$27.0 billion as of December 31, 2025. Depletion, depreciation and amortization ("DD&A") expense for the North America Exploration and Production segment was \$4.5 billion for the year ended December 31, 2025. In accordance with the Company's accounting policies, crude oil and natural gas properties in the North America Exploration and Production segment, excluding certain major components, are depleted

using the unit-of-production method based on proved reserves. Estimates of the Company's crude oil and natural gas reserves are based on estimated future prices and production costs, expected future rates of production and the timing and amount of future development expenditures. Management utilizes third party specialists, specifically independent qualified reserve evaluators, to evaluate its estimates of crude oil and natural gas reserves. These estimates are utilized for the calculation of DD&A expense.

The principal considerations for our determination that performing procedures relating to the impact of crude oil and natural gas reserves on PP&E assets in the North America Exploration and Production segment is a critical audit matter are the significant judgments required by management, including the use of Management's Specialists, when developing the estimates, specifically related to the estimates of crude oil and natural gas reserves in the North America Exploration and Production segment. This led to a high degree of auditor judgment, effort and subjectivity in performing procedures and evaluating evidence obtained related to the assumptions used in developing the estimates, including estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures. In addition, the audit effort involved the use of professionals with specialized skill and knowledge.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of internal controls in the North America Exploration and Production segment relating to management's estimates of the Company's crude oil and natural gas reserves and the calculation of DD&A expense. The work of Management's Specialists was used in performing the procedures to evaluate the reasonableness of the estimates of crude oil and natural gas reserves used to determine DD&A expense for the North America Exploration and Production segment. As a basis for using this work, Management's Specialists' qualifications were understood, and the Company's relationship with Management's Specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used by Management's Specialists, tests of data used by Management's Specialists and an evaluation of Management's Specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable. The procedures performed also included, among others, evaluating whether the assumptions used by Management's Specialists related to estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures were reasonable considering the current and past performance of the Company, consistency with industry pricing forecasts, and whether they were consistent with evidence obtained in other areas of the audit, as applicable. Additionally, these procedures also included testing the unit-of-production rates used to calculate DD&A expense.

/s/ PricewaterhouseCoopers LLP  
Chartered Professional Accountants

Calgary, Canada  
March 4, 2026

We have served as the Company's auditor since 1973.

# Consolidated Balance Sheets

As at December 31,

(millions of Canadian dollars)

	Note	2025	2024
<b>ASSETS</b>			
<b>Current assets</b>			
Cash and cash equivalents		\$ 673	\$ 131
Accounts receivable		3,999	4,126
Inventory	4	2,621	2,793
Prepays and other		301	279
Current portion of other long-term assets	9	70	76
		<b>7,664</b>	7,405
<b>Exploration and evaluation assets</b>	5	<b>2,651</b>	2,526
<b>Property, plant and equipment</b>	6	<b>77,645</b>	73,414
<b>Lease assets</b>	7	<b>3,001</b>	1,394
<b>Other long-term assets</b>	9	<b>869</b>	620
		<b>\$ 91,830</b>	<b>\$ 85,359</b>
<b>LIABILITIES</b>			
<b>Current liabilities</b>			
Accounts payable		\$ 1,105	\$ 1,079
Accrued liabilities		4,255	4,525
Current income taxes payable		597	92
Current portion of long-term debt	10	441	2,400
Current portion of other long-term liabilities	11	1,665	1,535
		<b>8,063</b>	9,631
<b>Long-term debt</b>	10	<b>16,176</b>	16,419
<b>Other long-term liabilities</b>	11	<b>11,936</b>	9,302
<b>Deferred income taxes</b>	12	<b>11,289</b>	10,539
		<b>47,464</b>	45,891
<b>SHAREHOLDERS' EQUITY</b>			
<b>Share capital</b>	13	<b>11,421</b>	11,064
<b>Retained earnings</b>		<b>32,726</b>	28,103
<b>Accumulated other comprehensive income</b>	14	<b>219</b>	301
		<b>44,366</b>	39,468
		<b>\$ 91,830</b>	<b>\$ 85,359</b>

Commitments and contingencies (note 19).

Approved by the Board of Directors on March 4, 2026.



**CATHERINE M. BEST**

Chair of the Audit Committee  
and Director



**N. MURRAY EDWARDS**

Executive Chairman of the  
Board of Directors and Director

# Consolidated Statements of Earnings

For the years ended December 31,

(millions of Canadian dollars, except per common share amounts)	Note	2025	2024	2023
Product sales	21	\$ 44,167	\$ 41,509	\$ 40,835
Less: royalties		(5,405)	(5,853)	(4,867)
<b>Revenue</b>		<b>38,762</b>	<b>35,656</b>	<b>35,968</b>
<b>Expenses</b>				
Production		9,155	8,093	8,480
Blending and feedstock <sup>(1)</sup>		8,071	7,931	7,732
Transportation <sup>(1)</sup>		2,751	2,053	1,570
Depletion, depreciation and amortization <sup>(2)</sup>	5,6,7	9,384	6,681	6,413
Administration		615	503	452
Share-based compensation	11	180	279	491
Asset retirement obligation accretion	11	380	389	366
Interest and other financing expense	17	834	592	636
Risk management (gain) loss	18	(18)	177	(2)
Foreign exchange (gain) loss		(762)	955	(279)
Gain on acquisitions, disposition, and remeasurement	6	(5,069)	—	—
Gain from investment	8	—	(56)	(56)
		<b>25,521</b>	<b>27,597</b>	<b>25,803</b>
<b>Earnings before taxes</b>		<b>13,241</b>	<b>8,059</b>	<b>10,165</b>
Current income tax expense	12	1,911	1,531	1,879
Deferred income tax expense	12	510	422	53
<b>Net earnings</b>		<b>\$ 10,820</b>	<b>\$ 6,106</b>	<b>\$ 8,233</b>
<b>Net earnings per common share <sup>(3)</sup></b>				
Basic	16	\$ 5.17	\$ 2.87	\$ 3.77
Diluted	16	\$ 5.16	\$ 2.85	\$ 3.74

(1) During 2025, the Company revised its presentation of transportation, blending and feedstock costs, showing the expenses on a disaggregated basis. The comparative periods presented have been updated to reflect the revision (note 1).

(2) Depletion, depreciation and amortization expense for the year ended December 31, 2025 includes a \$1,462 million (2024 – \$160 million; 2023 – \$436 million) non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a \$269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's Production Sharing Contract ("PSC") for the Espoir field in Offshore Africa, and a \$46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa (notes 5 and 6).

(3) Common share, per common share, dividend, and stock option amounts for 2023 have been updated to reflect the two for one common share split (note 1).

# Consolidated Statements of Comprehensive Income

For the years ended December 31,

(millions of Canadian dollars)

	2025	2024	2023
<b>Net earnings</b>	<b>\$ 10,820</b>	\$ 6,106	\$ 8,233
<b>Items that may be reclassified subsequently to net earnings</b>			
<b>Net change in derivative financial instruments designated as cash flow hedges</b>			
Unrealized income, net of taxes of \$2 million (2024 – \$nil; 2023 – \$nil)	18	2	2
Reclassification to net earnings, net of taxes of \$2 million (2024 – \$nil; 2023 – \$nil)	(22)	(4)	(5)
	(4)	(2)	(3)
<b>Foreign currency translation adjustment</b>			
Translation of net investment	(78)	131	(34)
<b>Other comprehensive (loss) income, net of taxes</b>	<b>(82)</b>	129	(37)
<b>Comprehensive income</b>	<b>\$ 10,738</b>	\$ 6,235	\$ 8,196

# Consolidated Statements of Changes in Equity

For the years ended December 31,

(millions of Canadian dollars)

	Note	2025	2024	2023
<b>Share capital</b>	13			
Balance – beginning of year		\$ 11,064	\$ 10,712	\$ 10,294
Issued upon exercise of stock options		264	280	372
Previously recognized liability on stock options exercised for common shares		273	358	435
Purchase of common shares under Normal Course Issuer Bid		(180)	(286)	(389)
Balance – end of year		11,421	11,064	10,712
<b>Retained earnings</b>				
Balance – beginning of year		28,103	28,948	27,672
Net earnings		10,820	6,106	8,233
Dividends on common shares	13	(4,910)	(4,537)	(4,028)
Purchase of common shares under Normal Course Issuer Bid, including tax	13	(1,287)	(2,414)	(2,929)
Balance – end of year		32,726	28,103	28,948
<b>Accumulated other comprehensive income</b>				
Balance – beginning of year	14	301	172	209
Other comprehensive (loss) income, net of taxes		(82)	129	(37)
Balance – end of year		219	301	172
<b>Shareholders' equity</b>		<b>\$ 44,366</b>	\$ 39,468	\$ 39,832

# Consolidated Statements of Cash Flows

For the years ended December 31,

(millions of Canadian dollars)

	Note	2025	2024	2023
<b>Operating activities</b>				
Net earnings		\$ 10,820	\$ 6,106	\$ 8,233
Non-cash items				
Depletion, depreciation and amortization	5,6,7	9,384	6,681	6,413
Share-based compensation		180	279	491
Asset retirement obligation accretion		380	389	366
Unrealized risk management loss		71	9	12
Unrealized foreign exchange (gain) loss		(870)	888	(260)
Gain on acquisitions, disposition, and remeasurement	6	(5,069)	—	—
Gain from investment	8	—	(50)	(34)
Deferred income tax expense		510	422	53
Realized foreign exchange on financing activities <sup>(1)</sup>		54	135	—
Abandonment expenditures	11	(771)	(646)	(509)
Other		(255)	(84)	5
Net change in non-cash working capital	20	672	(743)	(2,417)
Cash flows from operating activities		15,106	13,386	12,353
<b>Financing activities</b>				
(Repayment) issuance of bank credit facilities and commercial paper, net	10,20	(1,395)	5,466	—
Issuance of other long-term debt	10,20	1,634	2,639	—
Repayment of other long-term debt	10,20	(1,699)	(1,008)	(416)
Payment of lease liabilities	7,20	(361)	(325)	(285)
Issuance of common shares on exercise of stock options	13	264	280	372
Dividends on common shares		(4,871)	(4,429)	(3,891)
Purchase of common shares under Normal Course Issuer Bid	13	(1,449)	(2,660)	(3,318)
Cash flows used in financing activities		(7,877)	(37)	(7,538)
<b>Investing activities</b>				
Net expenditures on exploration and evaluation assets	5,21	(115)	(92)	(44)
Net expenditures on property, plant and equipment	6,21	(6,676)	(5,291)	(4,865)
Cash from AOSP asset swap	6	212	—	—
Acquisition of Chevron's assets	5,6,21	—	(9,163)	—
Net proceeds from investment	8	—	575	—
Net change in non-cash working capital	20	(108)	(124)	51
Cash flows used in investing activities		(6,687)	(14,095)	(4,858)
<b>Increase (decrease) in cash and cash equivalents</b>		<b>542</b>	<b>(746)</b>	<b>(43)</b>
<b>Cash and cash equivalents – beginning of year</b>		<b>131</b>	<b>877</b>	<b>920</b>
<b>Cash and cash equivalents – end of year</b>		<b>\$ 673</b>	<b>\$ 131</b>	<b>\$ 877</b>
<b>Interest paid on long-term debt</b>		<b>\$ 978</b>	<b>\$ 586</b>	<b>\$ 602</b>
<b>Income taxes paid, net</b>		<b>\$ 1,722</b>	<b>\$ 1,144</b>	<b>\$ 3,317</b>

(1) Realized foreign exchange on financing activities primarily relates to the repayment of US dollar denominated debt.

# Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

## 1. Accounting Policies

Canadian Natural Resources Limited (the "Company") is a senior independent crude oil and natural gas exploration, development and production company. The Company's exploration and production operations are focused in North America, largely in Western Canada; the United Kingdom ("UK") portion of the North Sea; and Côte d'Ivoire in Offshore Africa.

The Oil Sands Mining and Upgrading segment produces synthetic crude oil through bitumen mining and upgrading operations at Horizon Oil Sands ("Horizon") and through the Company's interest in the Athabasca Oil Sands Project ("AOSP").

Within Western Canada in the Midstream and Refining segment, the Company maintains certain activities that include pipeline operations, an electricity co-generation system and an investment in the North West Redwater Partnership ("NWRP"), a general partnership formed to upgrade and refine bitumen in the Province of Alberta.

The Company was incorporated in Alberta, Canada. The address of its registered office is 2100, 855 - 2 Street S.W., Calgary, Alberta, Canada.

The Company's consolidated financial statements and the related notes have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards"). The accounting policies adopted by the Company under the IFRS Accounting Standards are set out below. The Company has consistently applied the same accounting policies throughout all periods presented, except where the IFRS Accounting Standards permit new accounting standards to be adopted prospectively.

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

### (A) PRINCIPLES OF CONSOLIDATION

The consolidated financial statements have been prepared under the historical cost basis, unless otherwise required.

The consolidated financial statements include the accounts of the Company and all of its subsidiary companies and wholly owned partnerships. Subsidiaries include all entities over which the Company has control. Subsidiaries are consolidated from the date on which the Company obtains control. They are deconsolidated from the date that control ceases.

Certain of the Company's activities are conducted through joint arrangements in which two or more parties have joint control. Where the Company has determined that it has a direct ownership interest in jointly controlled assets and obligations for the liabilities (a "joint operation"), the assets, liabilities, revenue, and expenses related to the joint operation are included in the consolidated financial statements in proportion to the Company's interest. Where the Company has determined that it has an interest in jointly controlled entities (a "joint venture"), it uses the equity method of accounting. Under the equity method, the Company's initial and subsequent investments are recognized at cost and subsequently adjusted for the Company's share of the joint venture's income or loss, less distributions received. If the Company's share of the joint venture's loss equals or exceeds its interest in the joint venture, the Company discontinues recognizing its share of further losses. The Company resumes recognizing profits when its share of profits exceeds the accumulated share of losses not recognized.

Joint ventures accounted for using the equity method of accounting are tested for impairment whenever objective evidence indicates that the carrying amount of the investment may not be recoverable. Indications of impairment include a history of losses, significant capital expenditure overruns, liquidity concerns, financial restructuring of the investee or significant adverse changes in the technological, economic, or legal environment. The amount of the impairment is measured as the difference between the carrying amount of the investment and the higher of its fair value less costs of disposal and its value in use. Impairment losses are reversed in subsequent periods if the amount of the loss decreases, and the decrease can be related objectively to an event occurring after the impairment was recognized.

### (B) INVENTORY

Inventory is primarily comprised of product inventory, materials and supplies and other inventory, including emissions credits, and is carried at the lower of cost and net realizable value. Product inventory is comprised of crude oil held for sale, including pipeline linefill and crude oil stored in floating production, storage and offloading vessels ("FPSO"). Cost of product inventory consists of purchase costs, direct production costs, directly attributable overhead, and depletion, depreciation and amortization and is determined on a first-in, first-out basis. Net realizable value for product inventory is determined by reference to forward prices. Cost for materials and supplies consists of purchase costs and is based on a first-in, first-out or an average cost basis. Net realizable value for materials and supplies and other inventory, including emissions credits, is determined by reference to current market prices and regulated compliance rates. Emissions credit inventory generated in the normal course of business is initially measured in accordance with the Company's accounting policy for government grants.

## **(C) EXPLORATION AND EVALUATION ASSETS**

Exploration and evaluation ("E&E") assets consist of the Company's crude oil and natural gas exploration projects that are pending the determination of proved reserves.

E&E costs are initially capitalized and include costs directly associated with the acquisition of licenses, technical services and studies, seismic acquisition, exploration drilling and evaluation, overhead and administration expenses, and the estimate of any asset retirement costs. E&E costs do not include general prospecting or evaluation costs incurred prior to having obtained the legal rights to explore an area. These costs are recognized in net earnings.

Once the technical feasibility and commercial viability of E&E assets are determined and a development decision is made by management, the E&E assets are tested for impairment upon reclassification to property, plant and equipment. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when an assessment of proved reserves is made. An E&E asset is derecognized upon disposal or when no future economic benefits are expected to arise from its use. Any gain or loss arising on derecognition of the asset is recognized in net earnings within depletion, depreciation and amortization.

E&E assets are also tested for impairment when facts and circumstances suggest that the carrying amount of E&E assets may exceed their recoverable amount, by comparing the relevant costs to the fair value of the related Cash Generating Units ("CGUs"), aggregated at a segment level. Indications of impairment include leases approaching expiry, the existence of low benchmark commodity prices for an extended period of time, significant downward revisions in estimated probable reserves volumes, significant increases in estimated future exploration or development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks.

## **(D) PROPERTY, PLANT AND EQUIPMENT**

Property, plant and equipment is measured at cost less accumulated depletion and depreciation and recoverability charges. Assets under construction are not depleted or depreciated until available for their intended use.

### **Exploration and Production**

The cost of an asset comprises its acquisition costs, construction and development costs, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset.

When significant components of an item of property, plant and equipment, including crude oil and natural gas interests, have different useful lives, they are accounted for separately.

Crude oil and natural gas properties are depleted using the unit-of-production method over proved reserves, except for certain major components, which are depreciated using a straight-line method over their estimated useful lives. The unit-of-production depletion rate takes into account expenditures incurred to date, together with future development expenditures required to develop proved reserves.

### **Oil Sands Mining and Upgrading**

Capitalized costs for the Oil Sands Mining and Upgrading segment are reported separately from the Company's North America Exploration and Production segment. Capitalized costs include acquisition costs, construction and development costs, overburden removal costs incurred during the initial development of a mine at Horizon and AOSP, costs directly attributable to bringing the asset into operation, the estimate of any asset retirement costs, and applicable borrowing costs. Property acquisition costs are comprised of the aggregate amount paid and the fair value of any other consideration given to acquire the asset, with any gains or losses resulting from the difference in the re-measured fair value compared to the carrying value of the consideration recognized in net earnings.

Mine-related costs are depleted using the unit-of-production method based on proved reserves. Capitalized overburden removal costs are depleted over the life of the mining reserves that directly benefit from overburden removal activity. Costs of the upgraders and related infrastructure located on the Horizon and AOSP sites are depreciated on the unit-of-production method based on the estimated productive capacity of the respective upgraders and related infrastructure. Other equipment is depreciated on a straight-line basis over its estimated useful life ranging from 2 to 20 years.

### **Midstream, Refining and Head Office**

The Company capitalizes all costs that expand the capacity or extend the useful life of the midstream, refining and head office assets. Midstream and Refining assets are depreciated on a straight-line basis over their estimated useful lives ranging from 5 to 30 years. Head office assets are depreciated on a declining balance basis.

### **Useful lives**

The depletion rates and expected useful lives of property, plant and equipment are reviewed on an annual basis, with changes in depletion rates and useful lives accounted for prospectively.

## **Derecognition**

A property, plant and equipment asset is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is recognized in net earnings within depletion, depreciation and amortization.

## **Major maintenance expenditures**

Inspection costs associated with major turnarounds are capitalized and depreciated over the period to the next major turnaround. Maintenance costs are expensed as incurred.

## **Impairment**

The Company assesses property, plant and equipment for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset or group of assets may not be recoverable. Indications of impairment include the existence of low benchmark commodity prices for an extended period of time, significant downward revisions of estimated reserves volumes, significant increases in estimated future development expenditures, or significant adverse changes in the applicable legislative or regulatory frameworks. If an indication of impairment exists, the Company performs an impairment test related to the assets. Individual assets are grouped for impairment assessment purposes into CGUs, which are the lowest level at which there are identifiable cash inflows that are largely independent of the cash inflows of other groups of assets. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and a recoverability charge is taken through depletion, depreciation and amortization expense.

In subsequent periods, an assessment is made at each reporting date to determine whether there is any indication that previously recognized recoverability charges may no longer exist or may have decreased. If such indication exists, the recoverable amount is re-estimated and the net carrying amount of the asset is increased to its revised recoverable amount. The revised recoverable amount cannot exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, had no recoverability charge been recognized for the asset in prior periods. A reversal of a recoverability charge is recognized in net earnings. After a reversal, the depletion, depreciation and amortization charge is adjusted in future periods to allocate the asset's revised carrying amount over its remaining useful life.

## **(E) BUSINESS COMBINATIONS**

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed in a business combination are recognized at their fair value at the date of the acquisition. Any excess of the consideration paid over the fair value of the net assets acquired is recognized as an asset. Any excess of the fair value of the net assets acquired over the consideration paid is recognized in net earnings. For business combinations where the Company obtains control over an acquiree or acquiree's assets in which the Company has previously held interests, the acquisition is accounted for as a business combination achieved in stages. In these instances, the Company's previously held interests are re-measured to fair value as at the acquisition date with any gains or losses resulting from the difference in the fair value compared to the carrying value of the previously held interests recognized in net earnings.

## **(F) LEASES**

The Company recognizes a lease asset and a lease liability at the commencement date of the lease contract. The lease asset is initially measured at cost. The cost of a lease asset includes the amount of the initial measurement of the lease liability, lease payments made prior to the commencement date, initial direct costs and estimates of the asset retirement obligation, if any. Subsequent to initial recognition, the lease asset is depreciated using the straight-line method over the earlier of the end of the useful life of the lease asset or the lease term.

Lease liabilities are initially measured at the present value of lease payments discounted at the rate implicit in the lease, or if not readily determinable, the Company's incremental borrowing rate. Lease liabilities are remeasured if there are changes in the lease term or if the Company changes its assessment of whether it is reasonably certain it will exercise a purchase, extension or termination option. Lease liabilities are also remeasured if there are changes in the estimate of the amounts payable under the lease due to changes in indices or rates, or residual value guarantees. The Company reassesses its lease commitments and existing contracts when events or changes in circumstances indicate changes in business activities or expected use of the underlying assets.

Lease assets are reported in a separate caption in the consolidated balance sheets. Lease liabilities are reported within other long-term liabilities in the consolidated balance sheets.

Where the Company acts as the operator of a joint operation, the Company recognizes 100% of the related lease asset and lease liability. As the Company recovers its joint operation partners' share of the costs of the lease contract, these recoveries are recognized as other income in the consolidated statements of earnings.

## **(G) ASSET RETIREMENT OBLIGATIONS**

The Company provides for asset retirement obligations on all of its property, plant and equipment and certain exploration and evaluation assets based on current legislation and operating practices. Provisions for asset retirement obligations related to property, plant and equipment are recognized as a liability in the period in which they are incurred. Provisions are measured at the present value of management's best estimate of expenditures required to settle the obligation as at the date of the balance sheets. Subsequent to the initial measurement, the obligation is adjusted to reflect the passage of time, changes in credit adjusted interest rates, and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as asset retirement obligation accretion expense, whereas changes due to discount rates or estimated future cash flows are capitalized to or derecognized from property, plant and equipment. Actual costs incurred upon settlement of the asset retirement obligation are charged against the provision.

## **(H) FOREIGN CURRENCY TRANSLATION**

### **Functional and presentation currency**

Items included in the financial statements of the Company's subsidiary companies and partnerships are measured using the currency of the primary economic environment in which the subsidiary operates (the "functional currency").

When the Company disposes of its entire interest in a foreign operation, the foreign currency gains or losses accumulated in other comprehensive income related to the foreign operation are recognized in net earnings.

## **(I) REVENUE RECOGNITION AND COSTS OF GOODS SOLD**

Revenue from the sale of crude oil and natural gas liquids ("NGLs") and natural gas products is recognized when performance obligations in the sales contract are satisfied and it is probable that the Company will collect the consideration to which it is entitled. Performance obligations are generally satisfied at the point in time when the product is delivered to a location specified in a contract and control passes to the customer. The Company assesses customer creditworthiness, both before entering into contracts and throughout the revenue recognition process.

Contracts for sale of the Company's products generally have terms of less than a year, with certain contracts extending beyond one year. Contracts in North America generally specify delivery of crude oil and NGLs and natural gas throughout the term of the contract. Contracts in the North Sea and Offshore Africa generally specify delivery of crude oil at a point in time.

Sales of the Company's crude oil and NGLs and natural gas products to customers are made pursuant to contracts based on prevailing commodity pricing at or near the time of delivery and volumes of product delivered. Revenues are typically collected in the month following delivery and accordingly, the Company has elected to apply the practical expedient to not adjust consideration for the effects of a financing component. Purchases and sales of crude oil and NGLs and natural gas with the same counterparty, made to facilitate sales to customers or potential customers, that are entered into in contemplation of one another, are combined and recorded as non-monetary exchanges and measured at the net settlement amount.

Revenue in the consolidated statements of earnings represents the Company's share of product sales net of royalty payments to governments and other mineral interest owners. The Company discloses the disaggregation of revenues from sales of crude oil and NGLs and natural gas in the segmented information in note 21. Related costs of goods sold are comprised of production, transportation, blending and feedstock, and depletion, depreciation and amortization expenses. These amounts have been separately presented in the consolidated statements of earnings.

## **(J) PRODUCTION SHARING CONTRACTS**

Production generated from Côte d'Ivoire in Offshore Africa is shared under the terms of various Production Sharing Contracts ("PSCs"). Product sales are divided into cost recovery oil and profit oil. Cost recovery oil allows the Company to recover its capital and production costs and the costs carried by the Company on behalf of the respective government state oil company (the "Government"). Profit oil is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of profit oil attributable to the Company's equity interest is allocated to royalty expense and current income tax expense in accordance with the terms of the respective PSCs.

## **(K) INCOME TAX**

The Company follows the liability method of accounting for income taxes. Under this method, deferred income tax assets and liabilities are recognized based on the estimated income tax effects of temporary differences in the carrying amount of assets and liabilities in the consolidated financial statements and their respective tax bases.

Deferred income tax assets and liabilities are calculated using the substantively enacted income tax rates that are expected to apply when the asset or liability is recovered. Deferred income tax assets or liabilities are not recognized when they arise on the initial recognition of an asset or liability in a transaction (other than in a business combination or a transaction that, on initial recognition, gives rise to equal taxable and deductible temporary differences) that, at the time of the transaction, affects neither accounting nor taxable profit. Deferred income tax assets or liabilities are also not recognized on possible future distributions of retained earnings of subsidiaries where the timing of the distribution can be controlled by the Company and it is probable that a distribution will not be made in the foreseeable future, or when distributions can be made without incurring income taxes.

Deferred income tax assets for deductible temporary differences and tax loss carryforwards are recognized to the extent that it is probable that future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized. The carrying amount of deferred income tax assets is reviewed at each reporting date and is reduced if it is no longer probable that sufficient future taxable profits will be available against which the temporary differences or tax loss carryforwards can be utilized.

Current income tax is calculated based on net earnings for the period, adjusted for items that are non-taxable or taxed in different periods, using income tax rates that are substantively enacted at each reporting date.

## **(L) SHARE-BASED COMPENSATION**

The Company's Stock Option Plan (the "Option Plan") provides current employees with the right to elect to receive common shares or a cash payment in exchange for stock options surrendered. The liability for awards granted to employees is initially measured based on the grant date fair value of the awards and the number of awards expected to vest. The awards are remeasured each reporting period for subsequent changes in the fair value of the liability. Fair value is determined using the Black-Scholes valuation model under a graded vesting method. Expected volatility is estimated based on historic results. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by the employee and any previously recognized liability associated with the stock options are recorded as share capital.

The Performance Share Unit ("PSU") Plan provides certain executive employees of the Company with the right to receive a cash payment, the amount of which is determined by individual employee performance and the extent to which certain other performance measures are met. PSUs vest three years from original grant date. The liability for PSUs is initially measured in reference to the Company's share price and the number of awards expected to vest and is remeasured at each reporting period for changes in the fair value of the liability.

## **(M) FINANCIAL INSTRUMENTS**

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost; financial liabilities at amortized cost; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest method.

Cash and cash equivalents, accounts receivable and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are solely comprised of payments of principal and interest. Investments in publicly traded shares are classified as fair value through profit or loss. Accounts payable, accrued liabilities, certain other long-term liabilities, and long-term debt are classified as financial liabilities at amortized cost. Risk management assets and liabilities are classified as fair value through profit or loss.

Financial assets and liabilities are also categorized using a three-level hierarchy that reflects the significance of the inputs used in making fair value measurements for these assets and liabilities. The fair values of financial assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Fair values of financial assets and liabilities in Level 2 are based on inputs other than Level 1 quoted prices that are observable for the asset or liability either directly (as prices) or indirectly (derived from prices). The fair values of Level 3 financial assets and liabilities are not based on observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value due to the liquid nature of the asset or liability.

Transaction costs in respect of financial instruments at fair value through profit or loss are recognized in net earnings. Transaction costs in respect of other financial instruments are included in the initial measurement of the financial instrument.

### **Impairment of financial assets**

At each reporting date, on a forward-looking basis, the Company assesses the expected credit losses associated with its financial assets carried at amortized cost. Expected credit losses are measured as the difference between the cash flows that are due to the Company and the cash flows that the Company expects to receive, discounted at the effective interest rate determined at initial recognition. For trade accounts receivable, the Company applies the simplified approach permitted by IFRS 9, which requires expected lifetime credit losses to be recognized from initial recognition of the receivables. To measure expected credit losses, accounts receivable are grouped based on the number of days the receivables have been outstanding and internal credit assessments of the customers. Credit risk for longer-term receivables is assessed based on an external credit rating of the counterparty. For longer-term receivables with credit risk that has not increased significantly since the date of recognition, the Company measures the expected credit loss as the 12-month expected credit loss. Changes in the provision for expected credit loss are recognized in net earnings.

## **(N) RISK MANAGEMENT ACTIVITIES**

The Company periodically uses derivative financial instruments to manage its commodity price, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes. All derivative financial instruments are recognized in the consolidated balance sheets at their estimated fair value. The estimated fair value of derivative financial instruments has been determined based on appropriate internal valuation methodologies and/or third party indications. Fair values determined using valuation models require the use of assumptions concerning the amount and timing of future cash flows, discount rates and credit risk. In determining these assumptions, the Company primarily relied on external, readily-observable market inputs including quoted forward commodity prices and volatility, interest rate yield curves, foreign exchange rates, and other volatility factors. The carrying amount of a risk management asset and liability is adjusted for the Company's own credit risk.

The Company documents all derivative financial instruments that are formally designated as hedging transactions at the inception of the hedging relationship, in accordance with the Company's risk management policies. The effectiveness of the hedging relationship is evaluated, both at inception of the hedge and on an ongoing basis.

The Company periodically enters into commodity price contracts to manage anticipated sales and purchases of crude oil and natural gas in order to protect its cash flow for its capital expenditure programs. The effective portion of changes in the fair value of derivative commodity price contracts formally designated as cash flow hedges is initially recognized in other comprehensive income and is reclassified to risk management activities in net earnings in the same period or periods in which the commodity is sold or purchased. The ineffective portion of changes in the fair value of these designated contracts is recognized in risk management activities in net earnings. All changes in the fair value of non-designated crude oil and natural gas commodity price contracts are recognized in risk management activities in net earnings.

Embedded derivatives are derivatives that are included in a non-derivative host contract. Embedded derivatives are recorded at fair value separately from the host contract when their economic characteristics and risks are not closely related to the host contract, except when the host contract is an asset.

Realized gains or losses on the termination of financial instruments that have been designated as cash flow hedges are deferred under accumulated other comprehensive income and amortized into net earnings in the periods in which the underlying hedged items are recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized derivative gain or loss is recognized in net earnings. Realized gains or losses on the termination of financial instruments that have not been designated as hedges are recognized in net earnings.

Foreign currency forward contracts are periodically used to manage foreign currency cash requirements. The foreign currency forward contracts involve the purchase or sale of an agreed upon amount of US dollars at a specified future date at forward exchange rates. Changes in the fair value of foreign currency forward contracts designated as cash flow hedges are initially recorded in other comprehensive income and are reclassified to foreign exchange gains and losses when the hedged item is recognized in net earnings. Changes in the fair value of non-designated foreign currency forward contracts are recognized in risk management activities in net earnings.

The Company periodically enters into foreign currency put option contracts to manage its exposure to foreign currency exchange rate risk. The Company periodically sells put option contracts which grant the purchaser the right, but not the obligation, to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability valued at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

## **(O) GOVERNMENT GRANTS**

The Company receives or is eligible for government grants, including emissions credits. Government grants are recognized in net earnings when there is reasonable assurance that the Company will comply with the conditions attached to the grant and the grant will be received. Emissions performance and offset credits generated under the Alberta Technology Innovation and Emissions Reduction ("TIER") regulation are initially recorded at the value prescribed by the Alberta TIER fund compliance rates in effect at the time the credits are recognized.

## **(P) PER COMMON SHARE AMOUNTS**

The Company calculates basic earnings per common share by dividing net earnings by the weighted average number of common shares outstanding during the period. As the Company's Option Plan allows for the settlement of stock options in either cash or shares at the option of the holder, diluted earnings per common share is calculated using the more dilutive of cash settlement or share settlement under the treasury stock method.

## **(Q) SHARE CAPITAL**

Common shares are classified as equity. Costs directly attributable to the issue of new shares or options are included in equity as a deduction from proceeds, net of tax. When the Company acquires its own common shares, share capital is reduced by the average carrying value of the shares purchased. The excess of the purchase price over the average carrying value, including tax, is recognized as a reduction of retained earnings. Shares are cancelled upon purchase.

## **(R) COMMON SHARE SPLIT AND COMPARATIVE FIGURES**

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

## **2. Accounting Standards Issued But Not Yet Applied**

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

In May 2024, the IASB issued amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" to clarify the date of recognition and derecognition of some financial assets and liabilities, with a new exception for some financial liabilities settled using an electronic payment system. The amendments also clarify the classification of certain financial assets, and add disclosure requirements for financial instruments with certain contingent features and for equity investments designated at fair value through other comprehensive income. The amendments are effective January 1, 2026, and are required to be adopted retrospectively with early adoption permitted. The Company will adopt the amendments retrospectively without restating comparative information, as the impact of applying these amendments is not expected to be material to the consolidated financial statements.

## **3. Critical Accounting Estimates and Judgements**

The Company has made estimates, assumptions, and judgements regarding certain assets, liabilities, revenues, and expenses in the preparation of the consolidated financial statements, primarily related to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts. The estimates, assumptions, and judgements that have a significant risk of causing a material adjustment to the carrying amounts of assets and liabilities within the next financial year are addressed below.

### **(A) CRUDE OIL AND NATURAL GAS RESERVES**

Purchase price allocations, depletion, depreciation and amortization, asset retirement obligations, and amounts used in impairment calculations are based on estimates of crude oil and natural gas reserves. Reserves estimates, evaluated by the Company's Independent Qualified Reserves Evaluators, are based on estimated future prices and production costs, expected future rates of production, and the timing and amount of future development expenditures, all of which are subject to many uncertainties, interpretations, and judgements including the potential impact of climate related matters and in accordance with related government regulations. The Company expects that, over time, its reserves estimates will be revised upward or downward based on updated information.

### **(B) ASSET RETIREMENT OBLIGATIONS**

The Company provides for asset retirement obligations on its property, plant and equipment based on current legislation and operating practices. Estimated future costs include assumptions of dates of future abandonment, technological advances, and estimates of future inflation and discount rates. Actual costs may vary from the estimated provision due to changes in environmental legislation, the impact of inflation, changes in technology, changes in operating practices, revisions to work scope, changes in the date of abandonment due to changes in reserves life, and the potential impact of climate related matters and in accordance with related government regulations. These differences may have a material impact on the estimated provision.

### **(C) INCOME TAXES**

The Company is subject to income taxes in numerous legal jurisdictions. Accounting for income taxes requires the Company to interpret frequently changing laws and regulations, including changing income tax rates, and make certain judgements with respect to the application of tax law, estimating the timing of temporary difference reversals, and estimating the realizability of tax assets. There are many transactions and calculations for which the ultimate tax determination is uncertain. The Company recognizes a liability for a tax filing position based on its assessment of the probability that additional taxes may ultimately be due.

## **(D) FAIR VALUE OF DERIVATIVES AND OTHER FINANCIAL INSTRUMENTS**

The fair value of financial instruments that are not traded in an active market are determined using valuation techniques. The Company uses its judgement to select a variety of methods and make assumptions that are primarily based on market conditions existing at the end of each reporting period. The Company uses directly and indirectly observable inputs in measuring the value of financial instruments that are not traded in active markets, including quoted forward commodity prices and volatility, interest rate yield curves, discount rates, foreign exchange rates, and other volatility factors.

## **(E) PURCHASE PRICE ALLOCATIONS**

Purchase prices related to business combinations are allocated to the underlying acquired assets and liabilities based on their estimated fair value at the time of acquisition. The determination of fair value requires the Company to make estimates, assumptions, and judgements regarding future events. The allocation process is inherently subjective and impacts the amounts assigned to individually identifiable assets and liabilities, including the fair value of crude oil and natural gas properties, derived from the present value of estimated future cash flows from the assets, together with deferred income tax effects. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future depletion, depreciation and amortization expense and impairment tests.

## **(F) SHARE-BASED COMPENSATION**

The Company has made various assumptions in estimating the fair values of stock options granted under its Option Plan including expected volatility, expected exercise timing, and future forfeiture rates. At each period end, stock options outstanding are remeasured for changes in the estimated fair value of the liability.

## **(G) IDENTIFICATION OF CGUs**

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, shared infrastructures, and the way in which management monitors the Company's operations.

## **(H) IMPAIRMENT OF ASSETS**

The recoverable amount of a CGU or an individual asset has been determined as the higher of the CGUs' or the assets' fair value less costs of disposal and its value in use. These calculations require the use of estimates and assumptions and are subject to change as new information becomes available, including information on future commodity prices, expected production volumes, quantity of reserves, asset retirement obligations, future development and production costs, after-tax discount rates (currently ranging from 10% to 12%), and income taxes. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets and CGUs.

## **(I) LEASES**

Purchase, extension, and termination options are included in certain of the Company's leases to provide operational flexibility. To measure the lease liability, the Company uses judgement to assess the likelihood of exercising these options. These assessments are reviewed when significant events or circumstances indicate that the likelihood of exercising these options may have changed. The Company also uses estimates to determine its incremental borrowing costs if the interest rate implicit in the lease is not readily determinable.

## **(J) CONTINGENCIES**

Contingencies are subject to measurement uncertainty as the related financial impact will only be confirmed by the outcome of a future event. The assessment of contingencies requires the application of judgements and estimates including the determination of whether a present obligation exists and the reliable estimation of the timing and amount of cash flows required to settle the contingency.

## 4. Inventory

	2025	2024
Product inventory	\$ 736	\$ 986
Materials, supplies and other	1,885	1,807
	<b>\$ 2,621</b>	<b>\$ 2,793</b>

During 2025, approximately \$33 billion of purchased and produced inventory was recorded as an expense (2024 – approximately \$30 billion).

## 5. Exploration and Evaluation Assets

	Exploration and Production			Oil Sands Mining and Upgrading	Total
	North America	North Sea	Offshore Africa		
<b>Cost</b>					
At December 31, 2023	\$ 2,031	\$ —	\$ 100	\$ 77	\$ 2,208
Additions, net	102	—	6	—	108
Acquisition of Chevron's assets <sup>(1)</sup>	320	—	—	—	320
Transfers to property, plant and equipment	(45)	—	—	(7)	(52)
Derecognitions and other <sup>(2)</sup>	—	—	(62)	—	(62)
Foreign exchange adjustments	—	—	4	—	4
At December 31, 2024	2,408	—	48	70	2,526
Additions/Acquisitions, net <sup>(1)</sup>	<b>207</b>	—	—	<b>1</b>	<b>208</b>
Transfers to property, plant and equipment	<b>(21)</b>	—	—	<b>(14)</b>	<b>(35)</b>
Derecognitions and other <sup>(3)</sup>	—	—	<b>(46)</b>	—	<b>(46)</b>
Foreign exchange adjustments	—	—	<b>(2)</b>	—	<b>(2)</b>
At December 31, 2025	<b>\$ 2,594</b>	<b>\$ —</b>	<b>\$ —</b>	<b>\$ 57</b>	<b>\$ 2,651</b>

(1) Refer to note 6 for further details on acquisitions completed in 2024 and 2025.

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

(3) In connection with the Company's decision in 2025 to not pursue development of Kossipo in Offshore Africa, the Company derecognized \$46 million of exploration and evaluation assets through depletion, depreciation and amortization expense.

## 6. Property, Plant and Equipment

	Exploration and Production			Oil Sands Mining and Upgrading	Midstream and Refining	Head Office	Total
	North America	North Sea	Offshore Africa				
<b>Cost</b>							
At December 31, 2023	\$ 83,483	\$ 8,606	\$ 4,409	\$ 49,375	\$ 484	\$ 566	\$ 146,923
Additions	3,440	352	205	2,103	11	41	6,152
Acquisition of Chevron's assets	2,585	—	—	6,316	—	—	8,901
Transfers from exploration and evaluation assets	45	—	—	7	—	—	52
Derecognitions <sup>(1)</sup>	(589)	(18)	—	(456)	—	—	(1,063)
Foreign exchange adjustments and other	—	791	409	—	—	—	1,200
At December 31, 2024	88,964	9,731	5,023	57,345	495	607	162,165
Additions/Acquisitions, net	<b>4,447</b>	<b>1,223</b>	<b>547</b>	<b>1,841</b>	<b>8</b>	<b>92</b>	<b>8,158</b>
Transfers from exploration and evaluation assets	<b>21</b>	<b>—</b>	<b>—</b>	<b>14</b>	<b>—</b>	<b>—</b>	<b>35</b>
Derecognitions <sup>(1)</sup>	<b>(536)</b>	<b>(1,207)</b>	<b>—</b>	<b>(814)</b>	<b>—</b>	<b>—</b>	<b>(2,557)</b>
AOSP mines acquisition (100%) <sup>(2)</sup>	<b>—</b>	<b>—</b>	<b>—</b>	<b>15,488</b>	<b>—</b>	<b>—</b>	<b>15,488</b>
AOSP mines disposition (90%) <sup>(2)</sup>	<b>—</b>	<b>—</b>	<b>—</b>	<b>(12,087)</b>	<b>—</b>	<b>—</b>	<b>(12,087)</b>
Scotford and Quest disposition (10%) <sup>(2)</sup>	<b>—</b>	<b>—</b>	<b>—</b>	<b>(1,217)</b>	<b>—</b>	<b>—</b>	<b>(1,217)</b>
Foreign exchange adjustments and other	<b>—</b>	<b>(477)</b>	<b>(254)</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>(731)</b>
At December 31, 2025	<b>\$ 92,896</b>	<b>\$ 9,270</b>	<b>\$ 5,316</b>	<b>\$ 60,570</b>	<b>\$ 503</b>	<b>\$ 699</b>	<b>\$ 169,254</b>
<b>Accumulated depletion and depreciation</b>							
At December 31, 2023	\$ 58,840	\$ 8,382	\$ 3,358	\$ 11,105	\$ 213	\$ 444	\$ 82,342
Expense	3,741	96	192	2,086	16	26	6,157
Derecognitions <sup>(1)</sup>	(589)	(18)	—	(456)	—	—	(1,063)
Recoverability charge	—	160	—	—	—	—	160
Foreign exchange adjustments and other	18	772	335	30	—	—	1,155
At December 31, 2024	62,010	9,392	3,885	12,765	229	470	88,751
Expense	<b>4,470</b>	<b>92</b>	<b>97</b>	<b>2,538</b>	<b>17</b>	<b>31</b>	<b>7,245</b>
Derecognitions <sup>(1)</sup>	<b>(536)</b>	<b>(1,207)</b>	<b>—</b>	<b>(814)</b>	<b>—</b>	<b>—</b>	<b>(2,557)</b>
AOSP mines disposition (90%) <sup>(2)</sup>	<b>—</b>	<b>—</b>	<b>—</b>	<b>(2,656)</b>	<b>—</b>	<b>—</b>	<b>(2,656)</b>
Scotford and Quest disposition (10%) <sup>(2)</sup>	<b>—</b>	<b>—</b>	<b>—</b>	<b>(206)</b>	<b>—</b>	<b>—</b>	<b>(206)</b>
Recoverability charges	<b>—</b>	<b>1,462</b>	<b>269</b>	<b>—</b>	<b>—</b>	<b>—</b>	<b>1,731</b>
Foreign exchange adjustments and other	<b>(4)</b>	<b>(469)</b>	<b>(216)</b>	<b>(10)</b>	<b>—</b>	<b>—</b>	<b>(699)</b>
At December 31, 2025	<b>\$ 65,940</b>	<b>\$ 9,270</b>	<b>\$ 4,035</b>	<b>\$ 11,617</b>	<b>\$ 246</b>	<b>\$ 501</b>	<b>\$ 91,609</b>
<b>Net book value</b>							
<b>At December 31, 2025</b>	<b>\$ 26,956</b>	<b>\$ —</b>	<b>\$ 1,281</b>	<b>\$ 48,953</b>	<b>\$ 257</b>	<b>\$ 198</b>	<b>\$ 77,645</b>
At December 31, 2024	\$ 26,954	\$ 339	\$ 1,138	\$ 44,580	\$ 266	\$ 137	\$ 73,414

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

(2) Components of the AOSP asset swap are discussed below.

## AOSP ASSET SWAP TRANSACTION

On November 1, 2025, pursuant to a 2017 agreement with Shell Canada Limited and affiliates ("Shell") and following the satisfaction of certain conditions, the Company completed the AOSP asset swap with 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 allocation of the purchase price was based on management's best estimates of the fair value of the assets and liabilities exchanged as at the acquisition date. As a result of obtaining control of the AOSP mines, the transaction was accounted for as a business combination achieved in stages using the acquisition method of accounting. In accordance with IFRS Accounting Standards, at the acquisition date, the Company was deemed to have disposed of its pre-existing interest in the AOSP mines and re-acquired them at fair value, with any gains on remeasurement recognized in net earnings. As a result of the disposition of a 10% non-operated working interest in Scotford and Quest, the Company remeasured the 10% working interest to fair value at the acquisition date, with a gain on disposition recognized in net earnings.

### a) Net Assets Acquired and Consideration Exchanged

The following provides a summary of 100% of the identifiable net assets acquired, and the fair value of the consideration exchanged:

(\$ millions)	Net assets acquired	Purchase consideration/ previously held interests	Net
Fair value of the Company's interests in the AOSP mines <sup>(1) (2)</sup>	\$ 15,488	\$ (13,939)	\$ 1,549
Asset retirement obligation	(685)	616	(69)
Fair value, net of asset retirement obligation	14,803	(13,323)	1,480
Fair value of a 10% interest in Scotford and Quest <sup>(2)</sup>	—	(1,475)	(1,475)
Cash	153	59	212
Other working capital	8	60	68
Lease assets	1,510	—	1,510
Lease liabilities	(1,510)	—	(1,510)
Deferred income tax liability	(268)	—	(268)
	\$ 14,696	\$ (14,679)	\$ 17
Non-cash gain on disposition of a 10% interest in Scotford and Quest			464
Non-cash gain on remeasurement of the Company's 90%, pre-existing interest in the AOSP mines			4,508
Gain on acquisition, disposition, and remeasurement			\$ 4,989

(1) Net assets acquired represent a 100% interest in the AOSP mines, and purchase consideration and previously held interests represent a 90% interest in the AOSP mines.

(2) The Company determined the fair value of the AOSP mines, Scotford and Quest, using an estimate of future cash flows discounted at approximately 18%, with reference to comparable market transactions.

### b) Gain on Acquisition, Disposition, and Remeasurement

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 on remeasurement 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.

The fair value of the Company's interest in the AOSP mines, and non-operated interest in Scotford and Quest was determined in accordance with IFRS Accounting Standards, using an estimate of future cash flows discounted at approximately 18%, with reference to comparable market transactions, including the Company's acquisition of Chevron's assets in December 2024. The valuation incorporated asset-specific assumptions and required the use of level 3 fair value inputs. Key assumptions used in the valuation included the discount rate, estimated future prices, expected future rates of production, quantity of reserves, production expense, capital expenditures, and allocation of fair value between the AOSP mines, Scotford and Quest.

The Company determined that the acquisition date fair value of the previously held interest in the AOSP mines, net of asset retirement obligations, was \$13,323 million and utilized this estimate in its measurement of the purchase price consideration. The carrying value of the AOSP mines prior to the gain on remeasurement recorded in the transaction was \$8,815 million, net of asset retirement obligations. The Company also determined that the acquisition date fair value of the previously held 10% interest in Scotford and Quest was \$1,475 million and the associated carrying value prior to the gain on disposition recorded in the transaction was \$1,011 million, both net of asset retirement obligations.

In accordance with IFRS Accounting Standards, no value was attributed to potential entity-specific operational synergies. Additionally, the Company has not assigned reserves or attributed any fair value to the additional working interests in non-producing oil sands leases acquired.

### **c) Actual and Pro Forma Results for AOSP Asset Swap Transaction**

As a result of the AOSP asset swap, in the fourth quarter of 2025, revenue increased by approximately \$143 million and net operating income (comprised of revenue less production, blending and feedstock, and transportation expense) increased by approximately \$46 million. Including the impact of interest expense and depletion, depreciation and amortization from operations, earnings before tax increased as a result of the AOSP asset swap by approximately \$19 million for the fourth quarter of 2025. Depletion, depreciation and amortization also increased by an additional \$24 million for the fourth quarter of 2025 as a result of the gain on remeasurement of its 90% previously held interest in the AOSP mines.

If the AOSP asset swap had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately \$804 million and pro forma net operating income (comprised of revenue less production, blending and feedstock, and transportation expense) would have increased by approximately \$115 million for the year ended December 31, 2025. Including the impact of depletion, depreciation and amortization from operations, the Company estimates pro forma earnings before taxes would have increased by approximately \$97 million for the year ended December 31, 2025. Pro forma depletion, depreciation and amortization would have also increased by an additional \$145 million in 2025 as a result of the gain on remeasurement of its 90% previously held interest in the AOSP mines. If the Company had accounted for the Corridor pipeline as a lease as of January 1, 2025, pro forma transportation expense would have decreased by \$154 million, and pro forma interest expense and depletion, depreciation and amortization would have increased by \$136 million.

Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisition actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition date.

## **NORTH AMERICA EXPLORATION AND PRODUCTION ACQUISITIONS IN 2025**

During 2025, the Company acquired a number of producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment. These transactions were accounted for using the business combination method of accounting and are summarized below.

### **a) Grande Prairie NGLs and Natural Gas Acquisition**

During 2025, the Company acquired certain producing and non-producing NGLs and natural gas assets in the Grande Prairie area in the North America Exploration and Production segment for cash consideration of \$752 million, subject to final closing adjustments. Net assets acquired include exploration and evaluation assets of \$36 million, property, plant and equipment of \$733 million, and other assets of \$3 million. The Company also assumed associated asset retirement obligations of \$20 million. No net deferred tax liabilities were recognized on this transaction.

### **b) Palliser Block Crude Oil and NGLs, and Natural Gas Acquisition**

During 2025, the Company acquired certain producing and non-producing crude oil and NGLs, and natural gas assets in the Palliser Block in the North America Exploration and Production segment, including exploration and evaluation assets of \$119 million, property, plant and equipment of \$457 million, net working capital of \$76 million, deferred income tax assets of \$80 million, and assumed asset retirement obligations of \$350 million. Total cash consideration was approximately \$302 million and is subject to final closing adjustments. The Company recognized a gain on acquisition of \$80 million, representing the excess of the fair value of the net assets acquired compared to total purchase consideration.

### **c) Actual and Pro Forma Results for Grande Prairie and Palliser Block Acquisitions**

As a result of the Grande Prairie acquisition, revenue increased by approximately \$166 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately \$89 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately \$28 million for the period subsequent to the acquisition.

As a result of the Palliser Block acquisition, revenue increased by approximately \$279 million and net operating income (comprised of revenue less production and transportation expense) increased by approximately \$147 million for the period subsequent to the acquisition. Including the impact of depletion, depreciation and amortization, earnings before tax increased by approximately \$61 million for the period subsequent to the acquisition.

If the Grande Prairie and Palliser Block acquisitions had been completed on January 1, 2025, the Company estimates that pro forma revenue would have increased by approximately \$961 million and pro forma net operating income (comprised of revenue less production and transportation expense) would have increased by approximately \$520 million for the year ended December 31, 2025. Including the impact of depletion, depreciation and amortization, the Company estimates pro forma earnings before taxes would have increased by approximately \$241 million for the year ended December 31, 2025. Readers are cautioned that pro forma estimates are not necessarily indicative of the results of operations that would have resulted had the acquisitions actually occurred on January 1, 2025, or of future results. Pro forma results are based on historical information and reflect actual production in the period available for the assets as provided to the Company and do not include any synergies that have or may arise subsequent to the acquisition dates.

#### **d) Other Acquisitions**

For the year ended December 31, 2025, the Company also acquired a number of other producing and non-producing crude oil and NGLs, and natural gas assets in the North America Exploration and Production segment comprised of exploration and evaluation assets of \$17 million, property, plant and equipment of \$160 million, and assumed asset retirement and other obligations of \$51 million for total cash consideration of \$126 million.

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.

### **INTERNATIONAL MATTERS**

#### **a) North Sea**

The Company is advancing abandonment and decommissioning activities in the North Sea. Following a 2025 competitive tender for the Ninian South Platform, estimated abandonment costs were higher than originally budgeted. Accordingly, the Company updated its abandonment and decommissioning cost estimates for the Ninian Central and South Platforms and T-Block (Tiffany, Toni, and Thelma fields). Additionally, 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. Cessation of production has been accelerated to the first quarter of 2027 and associated crude oil reserves were de-booked.

As a result, during 2025, the Company recognized a non-cash charge of \$836 million (2024 – \$21 million; 2023 – \$113 million) comprised of a recoverability charge recognized in depletion, depreciation and amortization expense of \$1,462 million (2024 – \$160 million; 2023 – \$436 million), net of deferred tax recoveries of \$626 million (2024 – \$139 million; 2023 – \$323 million).

The Company's estimate of its asset retirement obligations, including its long-term abandonment projects in the North Sea and associated tax recoveries, are subject to revision in future periods as abandonment activities progress.

#### **b) Offshore Africa**

During 2025, the Company determined that it would not pursue an extension of its PSC for the Espoir Field, Block CI-26, in Offshore Africa, 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, as at December 31, 2025 the Company recognized a non-cash recoverability charge in depletion, depreciation and amortization expense of \$269 million.

### **OTHER MATTERS**

As at December 31, 2025, the Company determined that there were no indicators of impairment with respect to its property, plant and equipment and exploration and evaluation assets in the North America Exploration and Production and Oil Sands Mining and Upgrading segments. Although there were no indicators of impairment in these segments, the Company completed its normal course assessment of the recoverability of its property, plant and equipment and exploration and evaluation assets, and determined the carrying amounts of all its CGUs to be recoverable. The recoverability of the International CGUs is discussed in 'International Matters' above.

As at December 31, 2025, as a result of development activities and acquisitions undertaken since the establishment of its CGUs upon adoption of IFRS Accounting Standards, the Company reassessed its CGU structure within the North America Exploration and Production and Oil Sands Mining and Upgrading segments. This reassessment concluded that certain CGUs, which were located in adjacent geographic areas, produce similar products, and which were individually immaterial, should be aggregated into a single CGU. The aggregation of these CGUs did not have any impact on the recoverability of these CGUs under either the previous or revised CGU groupings. There were no changes to the Oil Sands Mining and Upgrading CGUs as a result of the AOSP asset swap, other than for the changing of ownership interest described in 'AOSP Asset Swap Transaction' above.

As at December 31, 2025, property, plant and equipment included project costs, not subject to depletion and depreciation, of \$466 million in the Oil Sands Mining and Upgrading segment (2024 – \$272 million in the Oil Sands Mining and Upgrading segment).

## ACQUISITION OF CHEVRON'S ASSETS

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

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

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

## 7. Leases

### LEASE ASSETS

	Product transportation and storage	Field equipment and power	Offshore vessels and equipment	Office leases and other	Total
At December 31, 2023	\$ 840	\$ 482	\$ 71	\$ 65	\$ 1,458
Additions	5	118	40	68	231
Depreciation	(96)	(135)	(51)	(20)	(302)
Foreign exchange adjustments and other	3	3	4	(3)	7
At December 31, 2024	752	468	64	110	1,394
Additions <sup>(1)</sup>	<b>1,554</b>	<b>413</b>	<b>45</b>	<b>43</b>	<b>2,055</b>
Depreciation	<b>(100)</b>	<b>(208)</b>	<b>(30)</b>	<b>(24)</b>	<b>(362)</b>
Derecognitions	<b>(3)</b>	<b>(29)</b>	<b>(29)</b>	—	<b>(61)</b>
Foreign exchange adjustments and other	<b>(4)</b>	<b>(10)</b>	<b>(7)</b>	<b>(4)</b>	<b>(25)</b>
At December 31, 2025	<b>\$ 2,199</b>	<b>\$ 634</b>	<b>\$ 43</b>	<b>\$ 125</b>	<b>\$ 3,001</b>

(1) During 2025, in connection with the AOSP asset swap (note 6), the Company became the sole contracted shipper on the Corridor pipeline and recognized \$1,510 million of lease assets, with an associated reduction in the Company's product transportation, purchases, and processing commitments (note 19).

### LEASE ASSETS, BY SEGMENT

As at December 31, 2025 and 2024, the Company had the following lease assets by segment:

	2025	2024
Exploration and Production		
North America	\$ 370	\$ 257
North Sea	32	25
Offshore Africa	35	93
Oil Sands Mining and Upgrading	2,457	932
Head Office	107	87
	<b>\$ 3,001</b>	<b>\$ 1,394</b>

## LEASE LIABILITIES

The Company measures its lease liabilities at the discounted value of its lease payments during the lease term. Lease liabilities as at December 31, 2025 and 2024 were as follows:

	<b>2025</b>	2024
Lease liabilities	<b>\$ 3,106</b>	\$ 1,464
Less: current portion	<b>373</b>	255
	<b>\$ 2,733</b>	\$ 1,209

In addition to the lease assets disclosed above, on an ongoing basis the Company enters into short-term leases related to its Exploration and Production and Oil Sands Mining and Upgrading activities.

Other amounts included in net earnings and cash flows during 2025 and 2024 are provided below:

	<b>2025</b>	2024
Expenses relating to short-term leases <sup>(1)</sup>	<b>\$ 306</b>	\$ 337
Interest expense on lease liabilities	<b>74</b>	69
Variable lease payments not included in the measurement of lease liabilities	<b>24</b>	59
Total cash outflows for leases <sup>(2)</sup>	<b>\$ 1,458</b>	\$ 1,333

(1) During 2025, the Company capitalized \$693 million (2024 – \$543 million) of short-term leases as additions to property, plant and equipment.

(2) Comprised of cash outflows relating to lease liabilities, short-term leases, and variable lease payments.

## 8. Investments

### INVESTMENT IN PRAIRIESKY ROYALTY LTD.

During 2024, the Company sold its 22.6 million common share investment in PrairieSky Royalty Ltd. ("PrairieSky") for \$25.65 per common share with net proceeds at close, after fees and expenses, of \$575 million. The Company's investment did not constitute significant influence, and was accounted for at fair value through profit or loss, measured at each reporting date. For the year ended December 31, 2024, the Company recognized a gain from investment of \$56 million (2023 – \$56 million gain) comprised of a fair value gain from investment of \$50 million (2023 – \$34 million gain) and dividend income of \$6 million (2023 – \$22 million).

## 9. Other Long-Term Assets

	<b>2025</b>	2024
Long-term prepayments, contracts and other <sup>(1)</sup>	<b>\$ 419</b>	\$ 313
Prepaid cost of service tolls	<b>229</b>	166
Long-term inventory	<b>291</b>	204
Risk management (note 18)	<b>—</b>	13
	<b>939</b>	696
Less: current portion	<b>70</b>	76
	<b>\$ 869</b>	\$ 620

(1) Includes physical product sales contracts, interest on Petroleum Revenue Tax ("PRT") and corporate tax recoveries in the North Sea (note 6), and the unamortized cost of contributions to the Company's employee bonus program.

### INVESTMENT IN NORTH WEST REDWATER PARTNERSHIP

The Company has a 50% equity investment in NWRP. NWRP operates a bitumen upgrader and refinery with an output capacity of approximately 80,000 barrels per day. The refinery processes approximately 50,000 barrels per day of bitumen feedstock, including 12,500 barrels per day of bitumen feedstock for the Company (25% toll payer) and 37,500 barrels per day of bitumen feedstock for the Alberta Petroleum Marketing Commission ("APMC") (75% toll payer), an agent of the Government of Alberta. The Company is unconditionally obligated to pay its 25% pro rata share of the debt component of the monthly fee-for-service toll over the 40-year tolling period until 2058 (note 19). Sales of diesel and other refined products and associated refining tolls are recognized in the Midstream and Refining segment (note 21).

As at December 31, 2025, NWRP had \$1,583 million (December 31, 2024 – \$1,459 million) outstanding under its unsecured commercial paper program. NWRP has a \$1,900 million syndicated credit facility that reserves capacity for amounts outstanding under its commercial paper program and for a debt service reserve equal to six months of anticipated facility interest and fees. As at December 31, 2025, the facility was undrawn.

During 2025, NWRP repaid and cancelled \$250 million of the non-revolving portion of the syndicated credit facility.

During 2024, NWRP amended its syndicated credit facility to extend the revolving portion originally maturing June 2025 to June 2027, and reduce the authorized limit on the revolving portion by \$275 million to \$1,900 million. In 2024, NWRP repaid \$657 million on its non-revolving facility, and reduced the authorized limit to \$250 million.

As at December 31, 2025, NWRP had \$8,750 million in long-term notes outstanding (December 31, 2024 – \$8,750 million).

During 2024, NWRP repaid \$500 million of 3.20% series A bonds. Additionally, in 2024 NWRP issued \$700 million of 4.85% series P bonds due June 2034 and \$600 million of 5.08% series Q bonds due June 2054.

NWRP also has short-term borrowings under a \$300 million syndicated credit facility ("demand operating facility") (December 31, 2024 – \$300 million). As at December 31, 2025, NWRP had borrowings of \$50 million under the demand operating facility (December 31, 2024 – \$103 million).

The assets, liabilities, partners' equity, product sales, and equity income related to NWRP at December 31, 2025 and 2024 were comprised as follows:

	<b>2025</b>	2024
Current assets	<b>\$ 493</b>	\$ 535
Non-current assets	<b>\$ 10,298</b>	\$ 10,286
Current liabilities	<b>\$ 2,953</b>	\$ 2,082
Non-current liabilities	<b>\$ 8,829</b>	\$ 9,757
Partners' equity	<b>\$ (991)</b>	\$ (1,018)
Partners' equity at Company's 50% interest	<b>\$ (496)</b>	\$ (509)
Revenue <sup>(1)</sup>	<b>\$ 1,365</b>	\$ 1,490
Net income <sup>(2)</sup>	<b>\$ 26</b>	\$ 92

(1) Included in NWRP's revenue for 2025 is \$315 million (2024 – \$325 million) related to the Company's 25% share of the refining toll.

(2) Included in the net income for 2025 is the impact of depreciation and amortization expense of \$265 million (2024 – \$346 million) and interest and other financing expense of \$457 million (2024 – \$502 million).

The carrying value of the Company's interest in NWRP is \$nil, and as at December 31, 2025, the cumulative unrecognized share of the equity loss and partnership distributions from NWRP was \$496 million (2024 – \$509 million). The Company's recovery of unrecognized equity losses from NWRP for 2025 was \$13 million (2024 – recovery of its share of unrecognized equity losses of \$46 million; 2023 – unrecognized equity loss of \$4 million).

## 10. Long-Term Debt

	2025	2024
<b>Canadian dollar denominated debt, unsecured</b>		
Medium-term notes		
3.42% debentures due December 1, 2026	\$ 441	\$ 441
2.50% debentures due January 17, 2028	225	225
3.30% debentures due December 8, 2028	550	—
3.75% debentures due February 8, 2031	550	—
4.15% debentures due December 15, 2031	500	500
4.55% debentures due February 8, 2036	550	—
4.85% debentures due May 30, 2047	300	300
	<b>3,116</b>	1,466
<b>US dollar denominated debt, unsecured</b>		
Bank credit facilities (December 31, 2025 – US\$2,860 million; December 31, 2024 – US\$3,393 million)	<b>3,922</b>	4,888
Commercial paper (December 31, 2025 – US\$nil; December 31, 2024 – US\$467 million)	—	672
US dollar debt securities		
3.90% due February 1, 2025 (US\$600 million)	—	864
2.05% due July 15, 2025 (US\$600 million)	—	864
3.85% due June 1, 2027 (US\$1,250 million)	1,715	1,801
5.00% due December 15, 2029 (US\$750 million)	1,029	1,080
2.95% due July 15, 2030 (US\$500 million)	685	720
7.20% due January 15, 2032 (US\$400 million)	548	576
6.45% due June 30, 2033 (US\$350 million)	480	504
5.40% due December 15, 2034 (US\$750 million)	1,029	1,080
5.85% due February 1, 2035 (US\$350 million)	480	504
6.50% due February 15, 2037 (US\$450 million)	617	649
6.25% due March 15, 2038 (US\$1,100 million)	1,509	1,585
6.75% due February 1, 2039 (US\$400 million)	548	576
4.95% due June 1, 2047 (US\$750 million)	1,029	1,080
	<b>13,591</b>	17,443
Long-term debt before transaction costs and original issue discounts, net	<b>16,707</b>	18,909
Less: original issue discounts, net <sup>(1)</sup>	14	12
transaction costs <sup>(1) (2)</sup>	76	78
	<b>16,617</b>	18,819
Less: current portion of commercial paper	—	672
current portion of long-term debt <sup>(1) (2)</sup>	441	1,728
	<b>\$ 16,176</b>	\$ 16,419

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

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

## **BANK CREDIT FACILITIES AND COMMERCIAL PAPER**

As at 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. Details of these facilities are described below. The Company also has certain other dedicated credit facilities supporting letters of credit.

- a \$100 million demand credit facility;
- a \$500 million revolving credit facility, maturing June 2027;
- a \$4,000 million non-revolving term credit facility, maturing December 2027;
- a \$2,425 million revolving syndicated credit facility, maturing June 2028; and
- a \$2,565 million revolving syndicated credit facility, with \$140 million maturing June 2027, and \$2,425 million maturing June 2029.

During 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.

During 2024, the Company extended its \$500 million revolving credit facility from February 2025 to February 2026. During 2025, the Company extended its \$500 million revolving credit facility originally maturing February 2026 to June 2027.

During 2024, the Company extended its \$2,425 million revolving syndicated credit facility originally maturing June 2025 to June 2028.

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

Borrowings under the Company's credit facilities may be made by way of pricing referenced to CORRA, SOFR, US base rate or Canadian prime rate.

The Company's borrowings under its US commercial paper program are authorized up to a maximum of US\$2,500 million. The Company reserves capacity under its revolving bank credit facilities for amounts outstanding under this program.

The Company's weighted average interest rate on bank credit facilities and commercial paper outstanding as at December 31, 2025 was 5.0% (December 31, 2024 – 5.4%), and on total long-term debt outstanding for the year ended December 31, 2025 was 5.0% (December 31, 2024 – 4.9%).

As at December 31, 2025, letters of credit and guarantees aggregating to \$840 million were outstanding (December 31, 2024 – \$1,542 million).

## **MEDIUM-TERM NOTES**

During 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 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 2024, the Company repaid \$320 million of 3.55% medium-term notes.

During 2024, the Company issued \$500 million of 4.15% medium-term notes due December 2031.

## **US DOLLAR DEBT SECURITIES**

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

During 2025, the Company repaid US\$600 million of 2.05% US dollar debt securities due July 2025.

During 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 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.

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

During 2024, the Company issued US\$750 million of 5.00% notes due December 2029 and US\$750 million of 5.40% notes due December 2034.

## SCHEDULED DEBT REPAYMENTS

Scheduled debt repayments are as follows:

Year	Repayment
2026	\$ 441
2027	\$ 5,637
2028	\$ 775
2029	\$ 1,029
2030	\$ 685
Thereafter	\$ 8,140

## 11. Other Long-Term Liabilities

	2025	2024
Asset retirement obligations	\$ 9,743	\$ 8,607
Lease liabilities (note 7)	3,106	1,464
Share-based compensation	433	620
Transportation and processing contracts	186	58
Risk management (note 18)	65	8
Other	68	80
	<b>13,601</b>	10,837
Less: current portion	<b>1,665</b>	1,535
	<b>\$ 11,936</b>	\$ 9,302

## ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations are expected to be settled on an ongoing basis over a period of approximately 60 years and discounted using a weighted average discount rate of 4.9% (2024 – 4.8%; 2023 – 5.2%) and inflation rates of up to 2% (2024 – up to 2%; 2023 – up to 2%). Reconciliations of the discounted asset retirement obligations were as follows:

	2025	2024	2023
Balance – beginning of year	\$ 8,607	\$ 7,690	\$ 6,908
Liabilities incurred	34	28	25
Liabilities acquired, net	489	171	—
Liabilities settled	(771)	(646)	(509)
Asset retirement obligation accretion	380	389	366
Revision of cost, inflation, and timing estimates <sup>(1)</sup>	1,233	417	621
Change in discount rates	(129)	419	314
Foreign exchange adjustments	(100)	139	(35)
Balance – end of year <sup>(2)</sup>	<b>9,743</b>	8,607	7,690
Less: current portion	<b>956</b>	787	634
	<b>\$ 8,787</b>	\$ 7,820	\$ 7,056

(1) Includes normal course revisions of cost, inflation, and timing estimates, as well as revisions to decommissioning timing and costs in the North Sea and Offshore Africa (note 6).

(2) The Company's estimate of its total undiscounted and uninflated asset retirement obligations as at December 31, 2025 was \$17.6 billion (2024 – \$16.1 billion; 2023 – \$15.5 billion).

## Segmented Asset Retirement Obligations

	2025	2024
Exploration and Production		
North America	\$ 4,937	\$ 4,783
North Sea	2,629	1,724
Offshore Africa	275	197
Oil Sands Mining and Upgrading	1,901	1,902
Midstream and Refining	1	1
	<b>\$ 9,743</b>	<b>\$ 8,607</b>

## Asset Retirement Obligations Sensitivity

Changes in the Company's discount and inflation rates used to estimate its expected future cash outflow required to settle its asset retirement obligations would have the following impact:

	2025	2024
<b>Discount rate</b>		
1% increase	\$ (896)	\$ (883)
1% decrease	\$ 1,135	\$ 1,132
<b>Inflation rate</b>		
1% increase	\$ 1,171	\$ 1,166
1% decrease	\$ (934)	\$ (920)

## SHARE-BASED COMPENSATION

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

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

	2025	2024	2023
Balance – beginning of year	\$ 620	\$ 780	\$ 832
Share-based compensation expense	180	279	491
Cash payment for stock options surrendered and PSUs vested	(94)	(84)	(110)
Transferred to common shares	(273)	(358)	(435)
Other	—	3	2
Balance – end of year	433	620	780
Less: current portion	312	463	538
	<b>\$ 121</b>	<b>\$ 157</b>	<b>\$ 242</b>

Included within share-based compensation liability as at December 31, 2025 was \$47 million (2024 – \$99 million; 2023 – \$96 million) related to PSUs granted to certain executive employees.

The fair value of stock options outstanding was estimated using the Black-Scholes valuation model with the following weighted average assumptions:

	<b>2025</b>	2024	2023 <sup>(1)</sup>
Fair value	<b>\$ 9.73</b>	\$ 13.15	\$ 17.96
Share price	<b>\$ 46.49</b>	\$ 44.38	\$ 43.41
Expected volatility	<b>25.7%</b>	26.4%	30.9%
Expected dividend yield	<b>5.1%</b>	5.1%	4.6%
Risk free interest rate	<b>2.7%</b>	2.9%	3.6%
Expected forfeiture rate	<b>5.3%</b>	5.2%	5.4%
Expected stock option life <sup>(2)</sup>	<b>3.9 years</b>	4.1 years	4.2 years

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

(2) At original time of grant.

The intrinsic value of vested stock options at December 31, 2025 was \$121 million (2024 – \$181 million; 2023 – \$164 million).

## 12. Income Taxes

The provision for income tax was as follows:

<b>Expense (recovery)</b>	<b>2025</b>	2024	2023
Current corporate income tax – North America <sup>(1)</sup>	<b>\$ 2,193</b>	\$ 1,654	\$ 1,853
Current corporate income tax – North Sea	<b>(124)</b>	(41)	(6)
Current corporate income tax – Offshore Africa	<b>16</b>	57	73
Current PRT <sup>(2)</sup> – North Sea	<b>(184)</b>	(134)	(58)
Other taxes	<b>10</b>	(5)	17
Current income tax	<b>1,911</b>	1,531	1,879
Deferred corporate income tax	<b>887</b>	520	267
Deferred PRT <sup>(2)</sup> – North Sea	<b>(377)</b>	(98)	(214)
Deferred income tax	<b>510</b>	422	53
Income tax	<b>\$ 2,421</b>	\$ 1,953	\$ 1,932

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

(2) Petroleum Revenue Tax.

For the year ended December 31, 2025, in connection with the AOSP asset swap, the Company recognized deferred corporate income tax of \$1,037 million related to the gain on remeasurement of the previously held interest in the AOSP mines, and deferred corporate income tax of \$107 million related to the gain on disposition of the 10% interest in Scotford and Quest. Refer to note 6 for further details on the transaction.

For the year ended December 31, 2025, the Company recognized deferred tax recoveries comprised of a deferred corporate income tax recovery of \$165 million (2024 – \$50 million; 2023 – \$118 million) and a deferred PRT recovery of \$461 million (2024 – \$89 million; 2023 – \$205 million) in connection with the increase in the Company's estimate of future abandonment costs for the planned decommissioning activities at the Ninian field and T-Block in the North Sea (note 6).

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	<b>2025</b>	2024	2023
Canadian statutory income tax rate	<b>23.1%</b>	23.2%	23.3%
Income tax provision at statutory rate	<b>\$ 3,064</b>	\$ 1,870	\$ 2,364
Effect on income taxes of:			
UK PRT and other taxes	<b>(551)</b>	(237)	(255)
Impact of UK PRT and other taxes on corporate income tax	<b>225</b>	95	105
Foreign and domestic tax rate differentials	<b>(94)</b>	(112)	(104)
Non-taxable portion of capital losses (gains)	<b>(93)</b>	114	(35)
Stock options exercised for common shares	<b>25</b>	41	91
Revisions arising from prior year tax filings	<b>1</b>	43	(174)
Change in unrecognized capital loss carryforward asset	<b>(93)</b>	114	(35)
Other	<b>(63)</b>	25	(25)
Income tax	<b>\$ 2,421</b>	\$ 1,953	\$ 1,932

The following table summarizes the temporary differences that give rise to the net deferred income tax liability:

	<b>2025</b>	2024
Deferred income tax liabilities		
Property, plant and equipment and exploration and evaluation assets	<b>\$ 13,620</b>	\$ 12,647
Lease assets	<b>754</b>	316
Investment in North West Redwater Partnership	<b>880</b>	908
Taxable PRT for corporate income tax	<b>457</b>	336
Other	<b>161</b>	92
	<b>15,872</b>	14,299
Deferred income tax assets		
Asset retirement obligations	<b>(2,580)</b>	(2,437)
Lease liabilities	<b>(777)</b>	(332)
Share-based compensation	<b>(29)</b>	(35)
Loss carryforwards	<b>(4)</b>	(36)
Unrealized foreign exchange loss on long-term debt	<b>(52)</b>	(125)
Deferred PRT	<b>(1,126)</b>	(795)
Other	<b>(15)</b>	—
	<b>(4,583)</b>	(3,760)
Net deferred income tax liability	<b>\$ 11,289</b>	\$ 10,539

Movements in deferred tax assets and liabilities recognized in net earnings during the year were as follows:

	<b>2025</b>	2024	2023
Property, plant and equipment and exploration and evaluation assets	<b>\$ 667</b>	\$ 443	\$ 196
Lease assets	<b>62</b>	(22)	1
Unrealized foreign exchange on long-term debt	<b>73</b>	(86)	28
Unrealized risk management activities	<b>(14)</b>	(1)	—
Asset retirement obligations	<b>(73)</b>	(279)	(292)
Lease liabilities	<b>(67)</b>	26	(3)
Share-based compensation	<b>6</b>	(4)	2
Loss carryforwards	<b>47</b>	381	235
Investments	<b>—</b>	(54)	(2)
Investment in North West Redwater Partnership	<b>(28)</b>	4	1
Deferred PRT	<b>139</b>	58	86
Taxable PRT for corporate income tax	<b>(377)</b>	(98)	(214)
Other	<b>75</b>	54	15
	<b>\$ 510</b>	\$ 422	\$ 53

The following table summarizes the movements of the net deferred income tax liability during the year:

	<b>2025</b>	2024	2023
Balance – beginning of year	<b>\$ 10,539</b>	\$ 10,183	\$ 10,114
Deferred income tax expense	<b>510</b>	422	53
Foreign exchange adjustments	<b>52</b>	(66)	16
Acquisitions (note 6)	<b>188</b>	—	—
Balance – end of year	<b>\$ 11,289</b>	\$ 10,539	\$ 10,183

Current income taxes recognized in each operating segment will vary depending upon available income tax deductions related to the nature, timing and amount of capital expenditures incurred in any particular year.

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.

The Company has reviewed the Organization for Economic Co-operation and Development's Pillar Two model rules and has concluded it does not have a significant impact.

Deferred income tax assets are recognized for temporary differences to the extent that the realization of the related tax benefit through future taxable profits is probable. Deferred PRT assets will be recovered from the UK Government, directly or through other third parties, as related abandonment expenditures are made. The Company has not recognized deferred income tax assets with respect to taxable capital loss carryforwards in excess of \$1,000 million in North America, which can be carried forward indefinitely and only applied against future taxable capital gains. In addition, the Company has not recognized deferred income tax assets related to North American tax pools of approximately \$950 million, which can only be claimed against income from certain oil and gas properties.

Deferred income tax liabilities have not been recognized on the unremitted net earnings of wholly controlled subsidiaries. The Company is able to control the timing and amount of distributions and no taxes are payable on distributions from these subsidiaries provided that the distributions remain within certain limits.

## 13. Share Capital

### AUTHORIZED

Preferred shares issuable in a series.

Unlimited number of common shares without par value.

	2025		2024	
	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
<b>ISSUED COMMON SHARES</b>				
Balance – beginning of year	<b>2,102,996</b>	<b>\$ 11,064</b>	2,144,815	\$ 10,712
Issued upon exercise of stock options	<b>12,062</b>	<b>264</b>	13,531	280
Previously recognized liability on stock options exercised for common shares	—	<b>273</b>	—	358
Purchase of common shares under Normal Course Issuer Bid	<b>(33,480)</b>	<b>(180)</b>	(55,350)	(286)
Balance – end of year	<b>2,081,578</b>	<b>\$ 11,421</b>	2,102,996	\$ 11,064

### PREFERRED SHARES

Preferred shares are issuable in a series. If issued, the number of shares in each series, and the designation, rights, privileges, restrictions, and conditions attached to the shares will be determined by the Board of Directors of the Company.

### DIVIDENDS

The Company has paid regular quarterly dividends in each year since 2001. The dividend policy undergoes periodic review by the Board of Directors and is subject to change.

On March 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<sup>(1)</sup> per common share.

### NORMAL COURSE ISSUER BID

On March 10, 2025, the Company's application was approved for a Normal Course Issuer Bid ("NCIB") 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.

### SHARE-BASED COMPENSATION – STOCK OPTIONS

The Company's Stock Option Plan provides for the granting of stock options to employees. Stock options granted under the Stock Option Plan have terms ranging from five to six years to expiry and vest over a five-year period. The exercise price of each stock option granted is determined at the closing market price of the common shares on the TSX on the day prior to the grant. Each stock option granted provides the holder the choice to purchase one common share of the Company at the stated exercise price or receive a cash payment equal to the difference between the stated exercise price and the market price of the Company's common shares on the date of surrender of the stock option.

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

The Stock Option Plan is a "rolling 7%" plan, whereby the aggregate number of common shares that may be reserved for issuance under the plan shall not exceed 7% of the common shares outstanding from time to time.

The following table summarizes information relating to stock options outstanding at December 31, 2025 and 2024:

	2025		2024	
	Stock options (thousands)	Weighted average exercise price	Stock options (thousands)	Weighted average exercise price
Outstanding – beginning of year	50,806	\$ 33.90	52,410	\$ 26.80
Granted	19,457	\$ 43.53	15,906	\$ 44.82
Exercised for common shares	(12,062)	\$ 21.86	(13,531)	\$ 20.69
Surrendered for cash settlement	(524)	\$ 22.65	(384)	\$ 22.19
Forfeited	(2,943)	\$ 38.57	(3,595)	\$ 29.69
Outstanding – end of year	54,734	\$ 39.83	50,806	\$ 33.90
Exercisable – end of year	11,942	\$ 36.58	10,033	\$ 26.67

The range of exercise prices of stock options outstanding and exercisable at December 31, 2025 was as follows:

	Stock options outstanding			Stock options exercisable		
Range of exercise prices	Stock options outstanding (thousands)	Weighted average remaining term (years)	Weighted average exercise price	Stock options exercisable (thousands)	Weighted average exercise price	
\$10.38 – \$14.99	2,935	0.20	\$ 14.56	876	\$ 14.36	
\$15.00 – \$19.99	61	0.08	\$ 19.36	61	\$ 19.36	
\$20.00 – \$24.99	1,105	0.79	\$ 20.42	757	\$ 20.30	
\$25.00 – \$29.99	481	1.86	\$ 27.12	240	\$ 27.12	
\$30.00 – \$34.99	4,668	1.49	\$ 32.47	1,717	\$ 32.41	
\$35.00 – \$39.99	11,278	2.18	\$ 39.25	4,285	\$ 39.01	
\$40.00 – \$44.99	27,965	4.08	\$ 43.10	2,606	\$ 42.38	
\$45.00 – \$49.99	5,938	3.76	\$ 47.94	1,396	\$ 48.51	
\$50.00 – \$52.98	303	4.31	\$ 52.98	4	\$ 52.98	
	54,734	3.14	\$ 39.83	11,942	\$ 36.58	

## 14. Accumulated Other Comprehensive Income

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

	2025		2024	
Derivative financial instruments designated as cash flow hedges	\$	66	\$	70
Foreign currency translation adjustment		153		231
	\$	219	\$	301

## 15. Capital Disclosures

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

The Company's objectives when managing its capital structure are to maintain financial flexibility and balance to enable the Company to access capital markets to sustain its on-going operations and support its growth strategies. The Company primarily monitors capital on the basis of an internally derived financial measure referred to as its "debt to book capitalization ratio", which is the ratio of current and long-term debt less cash and cash equivalents divided by the sum of the carrying value of shareholders' equity plus current and long-term debt less cash and cash equivalents. The Company's internal targeted range for its debt to book capitalization ratio is 25% to 45%. The ratio may fall below or exceed the targeted range depending on the execution of the Company's capital program, commodity price and foreign currency volatility, and the timing of acquisitions. As at December 31, 2025, the ratio was within the target range at 26%.

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

	<b>2025</b>	2024
Long-term debt	<b>\$ 16,617</b>	\$ 18,819
Less: cash and cash equivalents	<b>673</b>	131
Long-term debt, net	<b>\$ 15,944</b>	\$ 18,688
Total shareholders' equity	<b>\$ 44,366</b>	\$ 39,468
Debt to book capitalization	<b>26%</b>	32%

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.

## 16. Net Earnings Per Common Share

	<b>2025</b>	2024	2023 <sup>(1)</sup>
Weighted average common shares outstanding – basic (thousands of shares)	<b>2,091,134</b>	2,125,804	2,182,623
Effect of dilutive stock options (thousands of shares)	<b>6,772</b>	14,625	21,625
Weighted average common shares outstanding – diluted (thousands of shares)	<b>2,097,906</b>	2,140,429	2,204,248
Net earnings	<b>\$ 10,820</b>	\$ 6,106	\$ 8,233
Net earnings per common share – basic	<b>\$ 5.17</b>	\$ 2.87	\$ 3.77
– diluted	<b>\$ 5.16</b>	\$ 2.85	\$ 3.74

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

In 2025, the Company excluded 29,366,000 potentially anti-dilutive stock options from the calculation of diluted earnings per common share (2024 – 12,144,000; 2023 – 6,461,000).

## 17. Interest and Other Financing Expense

	<b>2025</b>	2024	2023
Interest expense on long-term debt	<b>\$ 965</b>	\$ 604	\$ 627
Interest expense on lease liabilities	<b>74</b>	69	64
Interest expense on long-term debt and lease liabilities	<b>1,039</b>	673	691
Interest (income) and other expense	<b>(205)</b>	(81)	(55)
Interest and other financing expense	<b>\$ 834</b>	\$ 592	\$ 636

## 18. Financial Instruments

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

The estimated fair values of derivative financial instruments in Level 2 and Level 3 at each measurement date have been determined based on appropriate internal valuation methodologies and/or third party indications, including quoted forward prices for commodities, foreign exchange rates, interest yield curves, and other volatility factors.

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

<b>Asset (liability)</b>	<b>2025</b>	<b>2024</b>
Balance – beginning of year	\$ 5	\$ 9
Net change in fair value of outstanding derivative financial instruments recognized in:		
Risk management activities <sup>(1)</sup>	(68)	(6)
Foreign exchange	(1)	1
Other comprehensive income	(1)	1
Balance – end of year	(65)	5
Less: current portion	(8)	5
	<b>\$ (57)</b>	<b>\$ —</b>

(1) Risk management assets and liabilities are disclosed in note 9 and note 11, respectively.

Net (gain) loss from risk management activities for the years ended December 31, were as follows:

	<b>2025</b>	<b>2024</b>	<b>2023</b>
Net realized risk management (gain) loss	\$ (89)	\$ 168	\$ (14)
Net unrealized risk management loss	71	9	12
	<b>\$ (18)</b>	<b>\$ 177</b>	<b>\$ (2)</b>

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

	<b>2025</b>		<b>2024</b>	
	<b>Carrying amount</b>	<b>Level 1 Fair Value</b>	<b>Carrying amount</b>	<b>Level 1 Fair Value</b>
Fixed rate long-term debt <sup>(1) (2)</sup>	\$ 12,695	\$ 12,941	\$ 13,259	\$ 13,186

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

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

## RISK MANAGEMENT

The Company periodically uses derivative financial instruments to manage its commodity price, interest rate, and foreign currency exposures. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The following provides a summary of the carrying amounts of derivative financial instruments held and a reconciliation to the Company's consolidated balance sheets.

<b>Asset (liability)</b>	<b>2025</b>		<b>2024</b>	
<b>Derivatives held for trading</b>				
Natural gas financial instruments <sup>(1) (2) (3)</sup>	\$	(4)	\$	7
Natural gas embedded derivative <sup>(4)</sup>		(57)		—
Foreign currency forward contracts		(4)		(2)
	\$	(65)	\$	5
Included within:				
Current portion of other long-term assets	\$	—	\$	13
Current portion of other long-term liabilities		(8)		(8)
Other long-term liabilities		(57)		—
	\$	(65)	\$	5

(1) In 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.

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

(3) In 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.

(4) In 2025, the Company entered into a long-term natural gas supply agreement that contains an embedded derivative.

### Embedded Derivative Contract

During 2025, the Company entered into a long-term natural gas supply agreement to supply 140,000 MMBtu/d of natural gas for a term of 15 years, with delivery anticipated to begin in 2030 as all conditions precedent have been waived by the counterparty. Under the terms of the agreement, the Company will deliver natural gas to its counterparty in Illinois, USA and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction. The contract includes an embedded derivative as a result of the pricing structure, and the host contract is the natural gas sales agreement with a Chicago Citygate price.

The natural gas embedded derivative contract is categorized as Level 3 within the fair value hierarchy, as the fair value is determined using a discounted estimated cash flow model which incorporates significant unobservable inputs, including future natural gas pricing and a discount rate.

	Remaining term	Fair value (\$ millions)	Range of significant unobservable inputs	
			Forward Prices <sup>(1)</sup> (US\$/MMBtu)	Discount Rate
Natural gas embedded derivative liability	2030 – 2045	\$ 57	\$3.10 – \$7.53	4.6 %

(1) Forward prices refers to the differential between JKM and Chicago Citygate prices.

The Company recognizes a (gain) loss on risk management activities in the statements of earnings related to its natural gas embedded derivative. The (gain) loss is determined by the relative movements in fair value compared to the prior period balance sheet date.

The Level 3 fair value measurements of the embedded derivative could be materially impacted by a change in the discount rate and movements in natural gas prices. The following table summarizes the impacts to the fair value of the embedded derivative resulting from changes in the specified variable over the 15-year contract. These sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities.

	JKM price		Discount rate	
	US\$0.10/MMBtu increase	US\$0.10/MMBtu decrease	1% increase	1% decrease
Fair value – increase/(decrease)	\$ 52	\$ (52)	\$ (90)	\$ 105

## FINANCIAL RISK FACTORS

The Company's financial risks are consistent with those disclosed in notes 1 and 3.

### a) Market risk

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

#### COMMODITY PRICE RISK MANAGEMENT

The Company periodically uses commodity derivative financial instruments to manage its exposure to commodity price risk associated with the sale of its future crude oil and natural gas production, and with natural gas purchases. These financial instruments are entered into solely for hedging purposes and are not used for speculative purposes.

The Company's outstanding commodity derivative financial instruments are expected to be settled monthly based on the applicable index pricing for the respective contract month.

#### INTEREST RATE RISK MANAGEMENT

The Company is exposed to interest rate price risk on its fixed rate long-term debt and to interest rate cash flow risk on its floating rate long-term debt. The Company periodically enters into interest rate swap contracts to manage its fixed to floating interest rate mix on long-term debt. Interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amounts on which the payments are based. As at December 31, 2025, the Company had no interest rate swap contracts outstanding.

#### FOREIGN CURRENCY EXCHANGE RATE RISK MANAGEMENT

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

As at December 31, 2025, the Company had US\$1,500 million of foreign currency forward contracts outstanding (December 31, 2024 – US\$2,187 million), with original terms of up to 90 days, all of which were designated as derivatives held for trading (December 31, 2024 – US\$1,521 million), and US\$nil were designated as cash flow hedges (December 31, 2024 – US\$666 million).

As at December 31, 2025, the Company had no foreign currency put option contracts outstanding. The Company periodically sells put option contracts which grant the purchaser the right, but not the obligation, to exercise the contract on the expiry date (European option) and are designated as derivatives held for trading. The amount that may be payable upon exercise is initially recognized as a liability valued at the amount paid by the counterparty. The option is remeasured to fair value at each reporting date with gains and losses recognized in risk management activities in net earnings. If the option expires unexercised, the remaining liability is derecognized.

#### FINANCIAL INSTRUMENT SENSITIVITIES

The following table summarizes the annualized sensitivities of the Company's 2025 net earnings and other comprehensive income to changes in the fair value of financial instruments outstanding as at December 31, 2025, resulting from changes in the specified variable, with all other variables held constant. These sensitivities are prepared on a different basis than those disclosed in the Company's other continuous disclosure documents, are limited to the impact of changes in a specified variable applied to financial instruments only, and do not represent the impact of a change in the variable on the operating results of the Company taken as a whole. Further, these sensitivities are theoretical, as changes in one variable may contribute to changes in another variable, which may magnify or counteract the sensitivities. In addition, changes in fair value generally cannot be extrapolated because the relationship of a change in an assumption to the change in fair value may not be linear. These sensitivities exclude the impacts of the Company's embedded derivative, disclosed above.

	2025		2024	
	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income	Increase (decrease) to net earnings	Increase (decrease) to other comprehensive income
<b>Interest rate risk</b>				
Increase interest rate 1%	\$ (33)	\$ —	\$ (46)	\$ —
Decrease interest rate 1%	\$ 33	\$ —	\$ 46	\$ —
<b>Foreign currency exchange rate risk</b>				
Weakening of the Canadian dollar by US\$0.01	\$ (189)	\$ —	\$ (255)	\$ —
Strengthening of the Canadian dollar by US\$0.01	\$ 184	\$ —	\$ 248	\$ —

## b) Credit risk

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

### COUNTERPARTY CREDIT RISK MANAGEMENT

The Company's accounts receivable are mainly with customers in the crude oil and natural gas industry and are subject to normal industry credit risks. The Company manages these risks by reviewing its exposure to individual companies on a regular basis and, where appropriate, ensuring that parental guarantees or letters of credit are in place to minimize the impact in the event of default. As at December 31, 2025, the Company had 2 customers (2024 – 1; 2023 – 3), that are major international energy companies with investment grade ratings, that individually accounted for more than 10% of the Company's annual sales. As at December 31, 2025, substantially all of the Company's accounts receivable were due within normal trade terms, and the average expected credit loss was approximately 2% of the Company's accounts receivable balance (December 31, 2024 – 2%).

The Company is also exposed to possible losses in the event of nonperformance by counterparties to derivative financial instruments; however, the Company manages this credit risk by entering into agreements with counterparties that are substantially all investment grade financial institutions. As at December 31, 2025, the Company had net risk of \$nil with specific counterparties related to derivative financial instruments (December 31, 2024 – \$11 million). The carrying amount of financial assets approximates the maximum credit exposure.

## c) Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities.

Management of liquidity risk requires the Company to maintain sufficient cash and cash equivalents, along with other sources of capital, consisting primarily of cash flow from operating activities, available credit facilities, commercial paper, and access to debt capital markets, to meet obligations as they become due. The Company believes it has adequate bank credit facilities to provide liquidity to manage fluctuations in the timing of the receipt and/or disbursement of operating cash flows.

The maturity dates of the Company's financial liabilities were as follows:

<b>As at December 31, 2025</b>		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	\$	1,105	\$ —	\$ —	\$ —
Accrued liabilities	\$	4,255	\$ —	\$ —	\$ —
Long-term debt <sup>(1)</sup>	\$	441	\$ 5,637	\$ 2,489	\$ 8,140
Other long-term liabilities <sup>(2)</sup>	\$	381	\$ 268	\$ 659	\$ 1,863
Interest and other financing expense <sup>(3)</sup>	\$	971	\$ 910	\$ 1,860	\$ 3,678

As at December 31, 2024		Less than 1 year	1 to less than 2 years	2 to less than 5 years	Thereafter
Accounts payable	\$	1,079	\$ —	\$ —	\$ —
Accrued liabilities	\$	4,525	\$ —	\$ —	\$ —
Long-term debt <sup>(1)</sup>	\$	2,400	\$ 941	\$ 7,494	\$ 8,074
Other long-term liabilities <sup>(2)</sup>	\$	263	\$ 187	\$ 405	\$ 617
Interest and other financing expense <sup>(3)</sup>	\$	1,024	\$ 951	\$ 1,978	\$ 3,574

(1) Long-term debt represents principal repayments only and does not reflect interest, original issue discounts and premiums or transaction costs.

(2) Lease payments included within other long-term liabilities reflect principal payments only and are as follows; less than one year, \$373 million (2024 – \$255 million); one to less than two years, \$268 million (2024 – \$187 million); two to less than five years, \$654 million (2024 – \$405 million); and thereafter, \$1,811 million (2024 – \$617 million).

(3) Includes interest and other financing expense on long-term debt and other long-term liabilities. Payments were estimated based upon applicable interest and foreign exchange rates as at December 31, 2025 and December 31, 2024, respectively.

## 19. 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:

	2026	2027	2028	2029	2030	Thereafter
Product transportation, purchases, and processing <sup>(1) (2) (3) (4)</sup>	\$ 2,241	\$ 2,223	\$ 2,065	\$ 1,912	\$ 1,758	\$ 18,025
North West Redwater Partnership service toll <sup>(5)</sup>	\$ 116	\$ 95	\$ 96	\$ 95	\$ 95	\$ 3,878
Offshore vessels and equipment	\$ 99	\$ —	\$ —	\$ —	\$ —	\$ —
Field equipment and power <sup>(4)</sup>	\$ 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 Trans Mountain Expansion ("TMX") pipeline reflects interim tolls approved by the Canada Energy Regulator in 2023, and is subject to change pending the approval of final tolls.

(2) In 2025, in connection with the AOSP asset swap (note 6), 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.

(3) During 2024, the Company increased its total committed capacity on the TMX pipeline to 169,000 bbl/d, an incremental 75,000 bbl/d over the 20-year term.

(4) During 2024, the acquisition of Chevron's assets included approximately \$1,292 million of product transportation and processing commitments and approximately \$75 million of field equipment and power commitments.

(5) 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 (note 9).

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

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

## 20. Supplemental Disclosure of Cash Flow Information

	2025		2024		2023
Changes in non-cash working capital:					
Accounts receivable	\$ 125	\$	(940)	\$	368
Inventory	166		(616)		(219)
Prepays and other	(22)		(42)		(23)
Accounts payable	84		(340)		78
Accrued liabilities	(316)		851		(812)
Current income tax liabilities	504		326		(1,558)
Other long-term liabilities	23		(106)		(200)
Net changes in non-cash working capital	\$ 564	\$	(867)	\$	(2,366)
Relating to:					
Operating activities	\$ 672	\$	(743)	\$	(2,417)
Investing activities	(108)		(124)		51
	\$ 564	\$	(867)	\$	(2,366)

The following table summarizes movements in the Company's liabilities arising from financing activities for the years ended December 31, 2025 and 2024:

	Long-term debt		Lease liabilities		Liabilities from financing activities
At December 31, 2023	\$ 10,799	\$	1,555	\$	12,354
Changes from financing cash flows:					
Issuance of bank credit facilities and commercial paper, net <sup>(1)</sup>	5,466		—		5,466
Issuance of other long-term debt <sup>(1)</sup>	2,639		—		2,639
Repayment of other long-term debt <sup>(1)</sup>	(1,008)		—		(1,008)
Payment of lease liabilities	—		(325)		(325)
Non-cash changes:					
Lease additions	—		231		231
Changes in foreign exchange and fair value <sup>(2)</sup>	923		3		926
At December 31, 2024	\$ 18,819	\$	1,464	\$	20,283
Changes from financing cash flows:					
Repayment of bank credit facilities and commercial paper, net <sup>(1)</sup>	(1,395)		—		(1,395)
Issuance of other long-term debt <sup>(1)</sup>	1,634		—		1,634
Repayment of other long-term debt <sup>(1)</sup>	(1,699)		—		(1,699)
Payment of lease liabilities	—		(361)		(361)
Non-cash changes:					
Lease additions	—		2,055		2,055
Lease derecognitions	—		(61)		(61)
Changes in foreign exchange and fair value <sup>(2)</sup>	(742)		9		(733)
At December 31, 2025	\$ 16,617	\$	3,106	\$	19,723

(1) Includes original issue discounts and premiums, and directly attributable transaction costs.

(2) Includes foreign exchange (gains) losses, the amortization of original issue discounts and premiums and directly attributable transaction costs.

## 21. Segmented Information

The Company's exploration and production activities are conducted in three geographic segments: North America, North Sea and Offshore Africa. These activities include the exploration, development, production, and marketing of crude oil, natural gas liquids, and natural gas. The Company's Oil Sands Mining and Upgrading activities are reported in a separate segment from exploration and production activities. Midstream and Refining activities include the Company's pipeline operations, an electricity co-generation system, and NWRP.

Segmented revenue and segmented results include transactions between business segments. Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers are based on the location of the seller.

	North America			North Sea			Offshore Africa		
(millions of Canadian dollars)	2025	2024	2023	2025	2024	2023	2025	2024	2023
<b>Segmented product sales</b>									
Crude oil and NGLs <sup>(1) (2)</sup>	\$ 19,102	\$ 18,740	\$ 17,375	\$ 325	\$ 467	\$ 435	\$ 164	\$ 434	\$ 577
Natural gas <sup>(1)</sup>	2,287	1,415	2,375	13	7	7	30	42	51
Other income and revenue	92	6	10	—	4	—	1	4	9
<b>Total segmented product sales</b>	<b>21,481</b>	<b>20,161</b>	<b>19,760</b>	<b>338</b>	<b>478</b>	<b>442</b>	<b>195</b>	<b>480</b>	<b>637</b>
Less: royalties	(2,529)	(2,876)	(2,443)	(1)	(1)	(1)	(8)	(24)	(57)
<b>Segmented revenue</b>	<b>18,952</b>	<b>17,285</b>	<b>17,317</b>	<b>337</b>	<b>477</b>	<b>441</b>	<b>187</b>	<b>456</b>	<b>580</b>
<b>Segmented expenses</b>									
Production	3,567	3,249	3,617	469	440	342	79	109	141
Blending and feedstock <sup>(2) (3)</sup>	4,344	4,643	4,568	—	—	—	—	—	—
Transportation <sup>(3)</sup>	2,032	1,541	1,240	10	10	7	—	1	1
Depletion, depreciation and amortization <sup>(4)</sup>	4,582	3,831	3,679	1,573	279	494	432	297	213
Asset retirement obligation accretion	221	231	234	64	65	46	9	9	8
Risk management loss (commodity derivatives)	66	7	24	—	—	—	—	—	—
Gain on acquisitions, disposition, and remeasurement	(80)	—	—	—	—	—	—	—	—
<b>Total segmented expenses</b>	<b>14,732</b>	<b>13,502</b>	<b>13,362</b>	<b>2,116</b>	<b>794</b>	<b>889</b>	<b>520</b>	<b>416</b>	<b>363</b>
<b>Segmented earnings (loss)</b>	<b>\$ 4,220</b>	<b>\$ 3,783</b>	<b>\$ 3,955</b>	<b>\$ (1,779)</b>	<b>\$ (317)</b>	<b>\$ (448)</b>	<b>\$ (333)</b>	<b>\$ 40</b>	<b>\$ 217</b>
<b>Non-segmented expenses</b>									
Administration									
Share-based compensation									
Interest and other financing expense									
Risk management (gain) loss (other)									
Foreign exchange (gain) loss									
Gain from investment									
<b>Total non-segmented expenses</b>									
<b>Earnings before taxes</b>									
Current income tax									
Deferred income tax									
<b>Net earnings</b>									

(1) Product sales in the North America Exploration and Production and Oil Sands Mining and Upgrading segments originate in Canada.

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

(3) During 2025, the Company revised its presentation of transportation, blending and feedstock costs, showing the expenses on a disaggregated basis. The comparative periods presented have been updated to reflect the revision (note 1).

(4) Includes a \$1,462 million (2024 – \$160 million; 2023 – \$436 million) non-cash recoverability charge for revisions to abandonment and decommissioning costs in the North Sea, a \$269 million non-cash recoverability charge related to the decision to not pursue an extension of the Company's PSC for the Espoir field in Offshore Africa, and a \$46 million non-cash derecognition of exploration and evaluation assets related to the decision to not pursue development of Kossipo in Offshore Africa (notes 5 and 6).

Inter-segment Elimination and Other includes internal and corporate transportation and electricity charges. Production, processing, and other purchasing and selling activities, that are not included in the preceding segments are also reported in the segmented information as Inter-segment Elimination and Other.

Operating segments have been determined based on the nature of the Company's activities and the geographic locations in which the Company operates, and are consistent with the level of information regularly provided to and reviewed by the Company's chief operating decision makers.

Oil Sands Mining and Upgrading			Midstream and Refining			Inter-segment Elimination and Other			Total		
2025	2024	2023	2025	2024	2023	2025	2024	2023	2025	2024	2023
\$ 20,112	\$ 19,263	\$ 18,661	\$ 91	\$ 82	\$ 76	\$ 946	\$ 98	\$ 176	\$ 40,740	\$ 39,084	\$ 37,300
—	—	—	—	—	—	120	104	142	2,450	1,568	2,575
204	16	5	670	813	926	10	14	10	977	857	960
20,316	19,279	18,666	761	895	1,002	1,076	216	328	44,167	41,509	40,835
(2,867)	(2,952)	(2,366)	—	—	—	—	—	—	(5,405)	(5,853)	(4,867)
17,449	16,327	16,300	761	895	1,002	1,076	216	328	38,762	35,656	35,968
4,693	3,921	3,989	284	315	332	63	59	59	9,155	8,093	8,480
2,218	2,462	2,253	503	669	646	1,006	157	265	8,071	7,931	7,732
684	497	310	42	16	18	(17)	(12)	(6)	2,751	2,053	1,570
2,780	2,258	2,011	17	16	16	—	—	—	9,384	6,681	6,413
86	84	78	—	—	—	—	—	—	380	389	366
—	—	—	—	—	—	—	—	—	66	7	24
(4,989)	—	—	—	—	—	—	—	—	(5,069)	—	—
5,472	9,222	8,641	846	1,016	1,012	1,052	204	318	24,738	25,154	24,585
\$ 11,977	\$ 7,105	\$ 7,659	\$ (85)	\$ (121)	\$ (10)	\$ 24	\$ 12	\$ 10	\$ 14,024	\$ 10,502	\$ 11,383
									615	503	452
									180	279	491
									834	592	636
									(84)	170	(26)
									(762)	955	(279)
									—	(56)	(56)
									783	2,443	1,218
									13,241	8,059	10,165
									1,911	1,531	1,879
									510	422	53
									\$ 10,820	\$ 6,106	\$ 8,233

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

	2025			2024		
	Net expenditures	Non-cash and fair value changes <sup>(2)</sup>	Capitalized costs	Net expenditures	Non-cash and fair value changes <sup>(2)</sup>	Capitalized costs
<b>Exploration and evaluation assets</b>						
Exploration and Production						
North America <sup>(3)</sup>	\$ 115	\$ 71	\$ 186	\$ 406	\$ (29)	\$ 377
Offshore Africa	—	(46)	(46)	6	(62)	(56)
Oil Sands Mining and Upgrading	—	(13)	(13)	—	(7)	(7)
	<b>115</b>	<b>12</b>	<b>127</b>	<b>412</b>	<b>(98)</b>	<b>314</b>
<b>Property, plant and equipment</b>						
Exploration and Production						
North America <sup>(3)</sup>	4,249	(317)	3,932	5,627	(146)	5,481
North Sea	16	—	16	39	295	334
Offshore Africa	467	80	547	197	8	205
	<b>4,732</b>	<b>(237)</b>	<b>4,495</b>	<b>5,863</b>	<b>157</b>	<b>6,020</b>
Oil Sands Mining and Upgrading <sup>(3) (4)</sup>	1,844	1,381	3,225	8,104	(134)	7,970
Midstream and Refining	8	—	8	11	—	11
Head Office	92	—	92	41	—	41
	<b>6,676</b>	<b>1,144</b>	<b>7,820</b>	<b>14,019</b>	<b>23</b>	<b>14,042</b>
	<b>\$ 6,791</b>	<b>\$ 1,156</b>	<b>\$ 7,947</b>	<b>\$ 14,431</b>	<b>\$ (75)</b>	<b>\$ 14,356</b>

(1) This table provides a reconciliation of capitalized costs, reported in note 5 and note 6, to net expenditures reported in the investing activities section of the statements of cash flows. The reconciliation excludes the impact of foreign exchange adjustments.

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

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

(4) Includes the non-cash gain on remeasurement and gain on disposition related to the AOSP asset swap completed in 2025 (note 6).

## SEGMENTED ASSETS

	2025	2024
Exploration and Production		
North America	\$ 33,462	\$ 32,670
North Sea	789	702
Offshore Africa	1,398	1,412
Other	35	31
Oil Sands Mining and Upgrading	54,699	49,221
Midstream and Refining	1,142	1,099
Head Office	305	224
	<b>\$ 91,830</b>	<b>\$ 85,359</b>

## 22. Remuneration of Directors and Senior Management

### REMUNERATION OF NON-MANAGEMENT DIRECTORS

	2025	2024	2023
Fees earned	\$ 3	\$ 3	\$ 3

### REMUNERATION OF SENIOR MANAGEMENT <sup>(1)</sup>

	2025	2024	2023
Salary	\$ 2	\$ 2	\$ 2
Common stock option based awards	7	11	13
Annual incentive plans	6	6	5
Long-term incentive plans	19	20	19
	\$ 34	\$ 39	\$ 39

(1) Senior management identified above are consistent with the disclosure on Named Executive Officers provided in the Company's Information Circular to shareholders for the respective years.

# Supplementary Oil & Gas Information for the Fiscal Year Ended December 31, 2025 (Unaudited)

This supplementary crude oil and natural gas information is provided in accordance with the United States Financial Accounting Standards Board ("FASB") Topic 932 – "Extractive Activities – Oil and Gas" and where applicable, financial information is prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

For the years ended December 31, 2025, 2024, 2023, and 2022 the Company filed its reserves information under National Instrument 51-101 – "Standards of Disclosure of Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada.

There are significant differences in the type of volumes disclosed and the basis from which the volumes are economically determined under the United States Securities and Exchange Commission ("SEC") requirements and NI 51-101. The SEC requires disclosure of net reserves, after royalties, using 12-month average prices and current costs; whereas NI 51-101 requires gross reserves, before royalties, using forecast pricing and costs. Therefore the difference between the reported numbers under the two disclosure standards can be material.

For the purposes of determining proved crude oil and natural gas reserves for SEC requirements as at December 31, 2025, 2024, 2023, and 2022 the Company used the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. The Company has used the following 12-month average benchmark prices to determine its 2025 and 2024 reserves for SEC requirements.

	Crude Oil and NGLs						Natural Gas		
	WTI (US\$/bbl)	WCS (C\$/bbl)	Canadian Light Sweet (C\$/bbl)	Cromer LSB (C\$/bbl)	Brent (US\$/bbl)	Edmonton C5+ (C\$/bbl)	Henry Hub (US\$/MMBtu)	AECO (C\$/MMBtu)	BC Westcoast Station 2 (C\$/MMBtu)
<b>2025</b>	<b>65.68</b>	<b>76.91</b>	<b>87.03</b>	<b>85.79</b>	<b>68.59</b>	<b>90.25</b>	<b>3.70</b>	<b>1.75</b>	<b>1.10</b>
2024	74.88	80.78	96.35	93.44	78.81	98.90	2.37	1.28	0.91

A foreign exchange rate of US\$0.7131/C\$1.00 was used in the 2025 evaluation (2024 - US\$0.7325/C\$1.00), determined on the same basis as the 12-month average price.

## Net Proved Crude Oil and Natural Gas Reserves

The Company retains Independent Qualified Reserves Evaluators to evaluate and review the Company's proved crude oil, bitumen, synthetic crude oil ("SCO"), natural gas, and natural gas liquids ("NGLs") reserves.

- For the years ended December 31, 2025, 2024, 2023, and 2022, the reports by GLJ Ltd. ("GLJ") covered 100% of the Company's Oil Sands Mining and Upgrading SCO reserves. As of December 31, 2025, GLJ also evaluated the Company's mining bitumen reserves. With the inclusion of non-traditional resources within the definition of "oil and gas producing activities" in the SEC's modernization of oil and gas reporting rules, effective January 1, 2010 these reserves volumes are included within the Company's crude oil and natural gas reserves totals.
- For the years ended December 31, 2025 and 2024, the reports by Sproule International Limited, and for the years ended December 31, 2023 and 2022, the reports by Sproule Associates Limited and Sproule International Limited, covered 100% of the Company's crude oil, thermal bitumen, natural gas and NGLs reserves.

Proved crude oil and natural gas reserves, as defined within the SEC's Regulation S-X, are the estimated quantities of oil and gas that by analysis of geoscience and engineering data demonstrate with reasonable certainty to be economically producible, from a given date forward, from known reservoirs under existing economic conditions, operating methods and government regulations. Developed crude oil and natural gas reserves are reserves of any category that can be expected to be recovered from existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of drilling a new well; and through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Undeveloped crude oil and natural gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Estimates of crude oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following tables summarize the Company's proved and proved developed crude oil and natural gas reserves, net of royalties, as at December 31, 2025, 2024, 2023 and 2022:

<b>North America</b>								
<b>Crude Oil and NGLs (MMbbl) <sup>(1)</sup></b>	<b>Synthetic Crude Oil</b>	<b>Bitumen <sup>(2)</sup></b>	<b>Crude Oil</b>	<b>NGLs</b>	<b>North America Total</b>	<b>North Sea</b>	<b>Offshore Africa</b>	<b>Total</b>
<b>Net Proved Reserves</b>								
Reserves, December 31, 2022	5,390	2,546	321	375	8,632	11	57	8,700
Extensions and discoveries	162	67	14	37	280	—	—	280
Improved recovery	28	9	7	30	75	—	—	75
Purchases of reserves in place	—	—	—	—	—	—	—	—
Sales of reserves in place	—	—	—	(1)	(1)	—	—	(1)
Production	(141)	(102)	(27)	(20)	(289)	(5)	(4)	(298)
Economic revisions due to prices <sup>(3)</sup>	333	123	10	18	484	—	1	485
Revisions of prior estimates	68	26	(2)	3	94	3	1	98
Reserves, December 31, 2023	5,840	2,669	325	442	9,276	9	54	9,339
Extensions and discoveries	—	62	13	18	93	—	—	93
Improved recovery	1	7	2	10	21	—	—	21
Purchases of reserves in place	701	1	7	131	839	—	—	839
Sales of reserves in place	—	—	(1)	(2)	(2)	—	—	(2)
Production	(141)	(101)	(26)	(23)	(291)	(4)	(4)	(299)
Economic revisions due to prices <sup>(3)</sup>	(106)	(38)	—	(34)	(180)	—	—	(179)
Revisions of prior estimates	18	77	37	4	136	1	(2)	136
Reserves, December 31, 2024	6,313	2,676	356	547	9,892	6	48	9,947
Extensions and discoveries	—	<b>58</b>	<b>13</b>	<b>7</b>	<b>78</b>	—	—	<b>78</b>
Improved recovery	<b>1</b>	<b>21</b>	<b>4</b>	<b>32</b>	<b>58</b>	—	—	<b>58</b>
Purchases of reserves in place	—	<b>336</b>	<b>57</b>	<b>55</b>	<b>448</b>	—	—	<b>448</b>
Sales of reserves in place	—	—	—	—	—	—	—	—
Production	<b>(167)</b>	<b>(112)</b>	<b>(31)</b>	<b>(35)</b>	<b>(345)</b>	<b>(3)</b>	<b>(1)</b>	<b>(349)</b>
Economic revisions due to prices <sup>(3)</sup>	<b>17</b>	<b>155</b>	<b>10</b>	<b>62</b>	<b>244</b>	—	<b>1</b>	<b>246</b>
Revisions of prior estimates	<b>(261)</b>	<b>309</b>	<b>10</b>	<b>(9)</b>	<b>50</b>	<b>(3)</b>	<b>(9)</b>	<b>38</b>
Reserves, December 31, 2025	<b>5,903</b>	<b>3,443</b>	<b>420</b>	<b>660</b>	<b>10,425</b>	—	<b>40</b>	<b>10,465</b>
<b>Net Proved Developed Reserves</b>								
December 31, 2022	5,389	582	238	121	6,330	5	34	6,369
December 31, 2023	5,804	610	225	112	6,752	6	30	6,787
December 31, 2024	6,268	629	232	127	7,256	6	25	7,288
December 31, 2025	<b>5,855</b>	<b>1,326</b>	<b>258</b>	<b>183</b>	<b>7,622</b>	—	<b>25</b>	<b>7,647</b>

(1) Information in the reserves data tables may not add due to rounding.

(2) Bitumen as defined by the SEC, "is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis." Under this definition, all the Company's thermal bitumen, mining bitumen and primary heavy crude oil reserves have been classified as bitumen.

(3) Includes changes due to commodity price and resulting royalty volumes.

2025 total proved Crude Oil and NGLs reserves increased by 518 MMbbl:

- Extensions and discoveries: Increase of 78 MMbbl primarily due to extension drilling/future offset additions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Improved recovery: Increase of 58 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs), Bitumen and Crude Oil properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) properties.
- Purchases of reserves in place: Increase of 448 MMbbl primarily due to acquisitions at various Bitumen, Crude Oil and natural gas (NGLs) properties.
- Production: Decrease of 349 MMbbl.
- Economic revisions due to prices: Increase of 246 MMbbl primarily at various Bitumen and Oil Sands Mining and Upgrading (SCO) properties due to lower bitumen pricing, resulting in lower royalties and higher net reserves.
- Revisions of prior estimates: Increase of 38 MMbbl primarily due to improved performance at various Bitumen and Crude Oil properties, partially offset by negative revisions at various natural gas (NGLs), Offshore Africa and North Sea properties, as well as a category transfer at Oil Sands Mining and Upgrading from SCO to Bitumen.

2024 total proved Crude Oil and NGLs reserves increased by 607 MMbbl:

- Extensions and discoveries: Increase of 93 MMbbl primarily due to extension drilling/future offset additions at various Bitumen, natural gas (NGLs) and Crude Oil properties.
- Improved recovery: Increase of 21 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs) and Crude Oil and Bitumen properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) properties.
- Purchases of reserves in place: Increase of 839 MMbbl primarily due to acquisitions at Oil Sands Mining and Upgrading (SCO) and various natural gas (NGLs) and Crude Oil properties in Alberta.
- Sales of reserves in place: Decrease of 2 MMbbl primarily due to dispositions from various natural gas (NGLs) properties in Alberta.
- Production: Decrease of 299 MMbbl.
- Economic revisions due to prices: Decrease of 179 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and various Bitumen properties due to higher bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Increase of 136 MMbbl primarily due to improved performance at various Bitumen, natural gas (NGLs) and Crude Oil properties as well as transfers from beyond the 50-year reserves life cutoff at Oil Sands Mining and Upgrading (SCO).

2023 total proved Crude Oil and NGLs reserves increased by 639 MMbbl:

- Extensions and discoveries: Increase of 280 MMbbl primarily due to pit extensions at Oil Sands Mining and Upgrading (SCO) and infill drilling/future offset additions at various Bitumen, natural gas (NGLs) and Crude Oil properties.
- Improved recovery: Increase of 75 MMbbl primarily due to infill drilling/future offset additions at various natural gas (NGLs) and Crude Oil properties as well as improved recovery at Oil Sands Mining and Upgrading (SCO) and Bitumen properties.
- Sales of reserves in place: Decrease of 1 MMbbl primarily due to dispositions from various natural gas (NGLs) properties in Alberta.
- Production: Decrease of 298 MMbbl.
- Economic revisions due to prices: Increase of 485 MMbbl primarily at Oil Sands Mining and Upgrading (SCO) and various Bitumen properties due to higher bitumen pricing resulting in higher royalties and lower net reserves.
- Revisions of prior estimates: Increase of 98 MMbbl primarily due to transfers from beyond the 50-year reserves life cutoff at Oil Sands Mining and Upgrading (SCO) and improved performance at various Bitumen properties.

<b>Natural Gas</b> (Bcf) <sup>(1)</sup>	<b>North America</b>	<b>North Sea</b>	<b>Offshore Africa</b>	<b>Total</b>
<b>Net Proved Reserves</b>				
Reserves, December 31, 2022	12,217	4	25	12,246
Extensions and discoveries	1,185	—	—	1,185
Improved recovery	603	—	—	603
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	(6)	—	—	(6)
Production	(750)	(1)	(4)	(755)
Economic revisions due to prices <sup>(2)</sup>	87	—	1	88
Revisions of prior estimates	57	(1)	1	58
Reserves, December 31, 2023	13,393	3	23	13,419
Extensions and discoveries	202	—	—	202
Improved recovery	152	—	—	152
Purchases of reserves in place	1,090	—	—	1,090
Sales of reserves in place	(44)	—	—	(44)
Production	(765)	(1)	(3)	(769)
Economic revisions due to prices <sup>(2)</sup>	(3,860)	—	—	(3,860)
Revisions of prior estimates	988	1	(2)	987
Reserves, December 31, 2024	11,155	3	18	11,177
Extensions and discoveries	<b>105</b>	—	—	<b>105</b>
Improved recovery	<b>180</b>	—	—	<b>180</b>
Purchases of reserves in place	<b>799</b>	—	—	<b>799</b>
Sales of reserves in place	—	—	—	—
Production	<b>(900)</b>	<b>(1)</b>	<b>(2)</b>	<b>(903)</b>
Economic revisions due to prices <sup>(2)</sup>	<b>1,667</b>	—	—	<b>1,667</b>
Revisions of prior estimates	<b>700</b>	<b>(2)</b>	<b>(10)</b>	<b>688</b>
Reserves, December 31, 2025	<b>13,706</b>	—	<b>6</b>	<b>13,712</b>
<b>Net Proved Developed Reserves</b>				
December 31, 2022	4,956	1	19	4,975
December 31, 2023	4,029	1	10	4,040
December 31, 2024	3,347	3	7	3,357
December 31, 2025	<b>4,455</b>	—	<b>2</b>	<b>4,457</b>

(1) Information in the reserves data tables may not add due to rounding.

(2) Includes changes due to commodity price and resulting royalty volumes.

2025 total proved Natural Gas reserves increased by 2,536 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 105 Bcf primarily due to extension drilling/future offset additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 180 Bcf primarily due to infill drilling additions in the Montney and other unconventional formations of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 799 Bcf primarily due to acquisitions at various Natural Gas properties in Alberta.
- Production: Decrease of 903 Bcf.
- Economic revisions due to prices: Increase of 1,667 Bcf primarily due to higher natural gas pricing.
- Revisions of prior estimates: Increase of 688 Bcf primarily due to improved performance at various North America Natural Gas properties, partially offset by negative revisions at North Sea and Offshore Africa properties.

2024 total proved Natural Gas reserves decreased by 2,242 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 202 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 152 Bcf primarily due to infill drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Purchases of reserves in place: Increase of 1,090 Bcf primarily due to acquisitions at various Natural Gas properties in Alberta.
- Sales of reserves in place: Decrease of 44 Bcf primarily due to dispositions from various Natural Gas properties in Alberta.
- Production: Decrease of 769 Bcf.
- Economic revisions due to prices: Decrease of 3,860 Bcf primarily due to lower natural gas pricing.
- Revisions of prior estimates: Increase of 987 Bcf primarily due to improved performance at various Natural Gas properties as well as category transfers from probable to proved.

2023 total proved Natural Gas reserves increased by 1,173 Bcf primarily due to the following:

- Extensions and discoveries: Increase of 1,185 Bcf primarily due to extension drilling/future offset additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Improved recovery: Increase of 603 Bcf primarily due to infill drilling/future offsets additions in the Montney formation of northwest Alberta and northeast British Columbia.
- Sales of reserves in place: Decrease of 6 Bcf primarily due to dispositions from various Natural Gas properties in Alberta.
- Production: Decrease of 755 Bcf.
- Economic revisions due to prices: Increase of 88 Bcf primarily at various North America Natural Gas properties due to lower natural gas pricing resulting in lower royalties and higher net reserves.
- Revisions of prior estimates: Increase of 58 Bcf primarily due to category transfers from probable to proved partially offset by negative revisions in various North American core areas as a result of decreased performance.

## Capitalized Costs Related to Crude Oil and Natural Gas Activities

2025				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	\$ 153,466	\$ 9,270	\$ 5,316	\$ 168,052
Unproved properties	2,651	—	—	2,651
	<b>156,117</b>	<b>9,270</b>	<b>5,316</b>	<b>170,703</b>
Less: accumulated depletion and depreciation	<b>(77,557)</b>	<b>(9,270)</b>	<b>(4,035)</b>	<b>(90,862)</b>
Net capitalized costs	<b>\$ 78,560</b>	<b>\$ —</b>	<b>\$ 1,281</b>	<b>\$ 79,841</b>
2024				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	\$ 146,309	\$ 9,731	\$ 5,023	\$ 161,063
Unproved properties	2,478	—	48	2,526
	148,787	9,731	5,071	163,589
Less: accumulated depletion and depreciation	(74,775)	(9,392)	(3,885)	(88,052)
Net capitalized costs	\$ 74,012	\$ 339	\$ 1,186	\$ 75,537
2023				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Proved properties	\$ 132,858	\$ 8,606	\$ 4,409	\$ 145,873
Unproved properties	2,108	—	100	2,208
	134,966	8,606	4,509	148,081
Less: accumulated depletion and depreciation	(69,945)	(8,382)	(3,358)	(81,685)
Net capitalized costs	\$ 65,021	\$ 224	\$ 1,151	\$ 66,396

## Costs Incurred in Crude Oil and Natural Gas Activities

2025				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	\$ 3,534	\$ —	\$ —	\$ 3,534
Unproved	172	—	—	172
Exploration	36	—	(46)	(10)
Development	4,938	1,223	547	6,708
<b>Costs incurred</b>	<b>\$ 8,680</b>	<b>\$ 1,223</b>	<b>\$ 501</b>	<b>\$ 10,404</b>
2024				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	\$ 8,901	\$ —	\$ —	\$ 8,901
Unproved	320	—	—	320
Exploration	102	—	(56)	46
Development	5,543	352	205	6,100
<b>Costs incurred</b>	<b>\$ 14,866</b>	<b>\$ 352</b>	<b>\$ 149</b>	<b>\$ 15,367</b>
2023				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Property acquisitions				
Proved	\$ —	\$ —	\$ —	\$ —
Unproved	—	—	—	—
Exploration	43	—	3	46
Development	5,039	558	187	5,784
<b>Costs incurred</b>	<b>\$ 5,082</b>	<b>\$ 558</b>	<b>\$ 190</b>	<b>\$ 5,830</b>

## Results of Operations from Crude Oil and Natural Gas Producing Activities

The Company's results of operations from crude oil and natural gas producing activities for the years ended December 31, 2025, 2024, and 2023 are summarized in the following tables:

2025				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	\$ 29,490	\$ 339	\$ 187	\$ 30,016
Production	(8,260)	(469)	(79)	(8,808)
Transportation	(2,716)	(10)	—	(2,726)
Depletion, depreciation and amortization	(7,362)	(1,573)	(432)	(9,367)
Asset retirement obligation accretion	(307)	(64)	(9)	(380)
Petroleum revenue tax recovery	—	561	—	561
Income tax	(2,509)	486	83	(1,940)
<b>Results of operations</b>	<b>\$ 8,336</b>	<b>\$ (730)</b>	<b>\$ (250)</b>	<b>\$ 7,356</b>

2024				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	\$ 26,501	\$ 478	\$ 458	\$ 27,437
Production	(7,170)	(440)	(109)	(7,719)
Transportation	(2,038)	(10)	(1)	(2,049)
Depletion, depreciation and amortization	(6,089)	(279)	(297)	(6,665)
Asset retirement obligation accretion	(315)	(65)	(9)	(389)
Petroleum revenue tax recovery	—	232	—	232
Income tax	(2,526)	34	(12)	(2,504)
<b>Results of operations</b>	<b>\$ 8,363</b>	<b>\$ (50)</b>	<b>\$ 30</b>	<b>\$ 8,343</b>

2023				
(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Crude oil and natural gas revenue, net of royalties, blending and feedstock costs	\$ 26,773	\$ 442	\$ 581	\$ 27,796
Production	(7,606)	(342)	(141)	(8,089)
Transportation	(1,550)	(7)	(1)	(1,558)
Depletion, depreciation and amortization	(5,690)	(494)	(213)	(6,397)
Asset retirement obligation accretion	(312)	(46)	(8)	(366)
Petroleum revenue tax recovery	—	273	—	273
Income tax	(2,700)	70	(54)	(2,684)
<b>Results of operations</b>	<b>\$ 8,915</b>	<b>\$ (104)</b>	<b>\$ 164</b>	<b>\$ 8,975</b>

## Standardized Measure of Discounted Future Net Cash Flows from Proved Crude Oil and Natural Gas Reserves and Changes Therein

The following standardized measure of discounted future net cash flows from proved crude oil and natural gas reserves has been computed using the 12-month average price, defined by the SEC as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, costs as at the balance sheet date and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the crude oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and possible reserves;
- Future production of crude oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future prices and costs rather than 12-month average prices and costs as at the balance sheet date will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration and evaluation expenditures; and
- Future development and asset retirement obligations will differ from those estimated.

Future net revenues, development, production and asset retirement obligation costs have been based upon the estimates referred to above. The following tables summarize the Company's future net cash flows relating to proved crude oil and natural gas reserves based on the standardized measure as prescribed in FASB Topic 932 - "Extractive Activities - Oil and Gas":

	<b>2025</b>			
(millions of Canadian dollars)	<b>North America</b>	<b>North Sea</b>	<b>Offshore Africa</b>	<b>Total</b>
Future cash inflows	\$ 833,999	\$ —	\$ 3,742	\$ 837,741
Future production costs	(296,918)	—	(997)	(297,915)
Future development costs and asset retirement obligations	(94,826)	—	(1,052)	(95,878)
Future income taxes	(97,315)	—	(233)	(97,548)
Future net cash flows	<b>344,940</b>	<b>—</b>	<b>1,460</b>	<b>346,400</b>
10% annual discount for timing of future cash flows	(240,827)	—	(585)	(241,412)
Standardized measure of future net cash flows <sup>(1)</sup>	<b>\$ 104,113</b>	<b>\$ —</b>	<b>\$ 875</b>	<b>\$ 104,988</b>

(1) In 2025, the Company determined its North Sea reporting jurisdiction was no longer economic and de-booked all related reserves. With no proved reserves remaining, the table no longer includes future net cash flows or its components. Results from operations, income taxes, and asset retirement obligations will continue to be reported in the Company's consolidated financial statements.

	<b>2024</b>			
(millions of Canadian dollars)	<b>North America</b>	<b>North Sea</b>	<b>Offshore Africa</b>	<b>Total</b>
Future cash inflows	\$ 876,917	\$ 722	\$ 5,329	\$ 882,968
Future production costs	(286,440)	(414)	(1,661)	(288,515)
Future development costs and asset retirement obligations	(92,455)	(1,970)	(1,804)	(96,229)
Future income taxes	(111,073)	1,144	(413)	(110,342)
Future net cash flows	<b>386,949</b>	<b>(518)</b>	<b>1,451</b>	<b>387,882</b>
10% annual discount for timing of future cash flows	(275,139)	136	(721)	(275,724)
Standardized measure of future net cash flows <sup>(1)</sup>	<b>\$ 111,810</b>	<b>\$ (382)</b>	<b>\$ 730</b>	<b>\$ 112,158</b>

(1) Includes abandonment cost estimates for the Ninian field.

(millions of Canadian dollars)	North America	North Sea	Offshore Africa	Total
Future cash inflows	\$ 863,544	\$ 1,067	\$ 6,144	\$ 870,755
Future production costs	(276,498)	(636)	(1,880)	(279,014)
Future development costs and asset retirement obligations	(86,615)	(1,873)	(1,927)	(90,415)
Future income taxes	(113,516)	967	(508)	(113,057)
Future net cash flows	386,915	(475)	1,829	388,269
10% annual discount for timing of future cash flows	(278,814)	168	(887)	(279,533)
Standardized measure of future net cash flows <sup>(1)</sup>	\$ 108,101	\$ (307)	\$ 942	\$ 108,736

(1) Includes abandonment cost estimates for the Ninian field.

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	2025	2024	2023
Sales of crude oil and natural gas produced, net of production costs	\$ (18,544)	\$ (17,672)	\$ (18,174)
Net changes in sales prices and production costs	(19,233)	(11,189)	(47,145)
Extensions, discoveries and improved recovery	3,104	2,576	8,196
Changes in estimated future development costs	(890)	(2,101)	(1,511)
Purchases of proved reserves in place	5,971	15,463	—
Sales of proved reserves in place	—	(63)	(47)
Revisions of previous reserve estimates	5,322	(485)	6,647
Accretion of discount	14,369	14,059	17,769
Changes in production timing and other	671	2,507	(2,831)
Net change in income taxes	2,060	327	8,834
Net change	(7,170)	3,422	(28,262)
Balance - beginning of year	112,158	108,736	136,998
Balance - end of year	\$ 104,988	\$ 112,158	\$ 108,736

# Ten Year Review

Years ended December 31	2025	2024	2023	2022	2021	2020	2019	2018	2017	2016
<b>FINANCIAL INFORMATION</b> (C\$ millions, except per share amounts)										
Net earnings (loss)	<b>10,820</b>	6,106	8,233	10,937	7,664	(435)	5,416	2,591	2,397	(204)
Per share – basic (\$/share) <sup>(1)</sup>	<b>5.17</b>	2.87	3.77	4.82	3.24	(0.18)	2.27	1.06	1.02	(0.09)
Per share – diluted (\$/share) <sup>(1)</sup>	<b>5.16</b>	2.85	3.74	4.76	3.23	(0.18)	2.27	1.06	1.01	(0.09)
Cash flows from operating activities	<b>15,106</b>	13,386	12,353	19,391	14,478	4,714	8,829	10,121	7,262	3,452
Adjusted funds flow <sup>(2)</sup>	<b>15,460</b>	14,859	15,274	19,791	13,733	5,200	10,267	9,088	7,347	4,293
Per share – basic (\$/share) <sup>(1)(3)</sup>	<b>7.39</b>	6.99	7.00	8.72	5.81	2.20	4.31	3.73	3.13	1.95
Per share – diluted (\$/share) <sup>(1)(3)</sup>	<b>7.37</b>	6.94	6.93	8.61	5.79	2.20	4.30	3.71	3.11	1.94
Cash flows used in investing activities	<b>6,687</b>	14,095	4,858	4,987	3,703	2,819	7,255	4,814	13,102	3,811
Net capital expenditures <sup>(2)</sup>	<b>6,579</b>	14,431	4,909	5,136	4,676	2,957	6,825	4,441	16,855	3,527
Abandonment expenditures, net <sup>(2)</sup>	<b>771</b>	646	509	335	232	249	296	290	274	267
<b>Balance sheet information</b> (C\$ millions)										
Adjusted working capital <sup>(4)</sup>	<b>42</b>	174	712	(1,190)	(480)	626	241	(601)	513	1,056
Exploration and evaluation assets	<b>2,651</b>	2,526	2,208	2,226	2,250	2,436	2,579	2,637	2,632	2,382
Property, plant and equipment, net	<b>77,645</b>	73,414	64,581	64,859	66,400	65,752	68,043	64,559	65,170	50,910
Total assets	<b>91,830</b>	85,359	75,955	76,142	76,665	75,276	78,121	71,559	73,867	58,648
Long-term debt, net <sup>(5)</sup>	<b>15,944</b>	18,688	9,922	10,525	13,950	21,269	20,843	20,522	22,321	16,788
Shareholders' equity	<b>44,366</b>	39,468	39,832	38,175	36,945	32,380	34,991	31,974	31,653	26,267
<b>SHARE INFORMATION</b> <sup>(1)</sup>										
Common shares outstanding (thousands)	<b>2,081,578</b>	2,102,996	2,144,815	2,205,272	2,336,738	2,367,733	2,373,714	2,403,771	2,445,538	2,221,905
Weighted average shares outstanding – basic (thousands)	<b>2,091,134</b>	2,125,804	2,182,623	2,269,919	2,362,500	2,363,536	2,381,954	2,437,597	2,350,188	2,200,943
Weighted average shares outstanding – diluted (thousands)	<b>2,097,906</b>	2,140,429	2,204,248	2,298,363	2,373,114	2,363,536	2,386,211	2,447,517	2,365,645	2,200,943
Dividends declared (\$/share) <sup>(6)</sup>	<b>2.35</b>	2.14	1.85	2.30	1.00	0.85	0.75	0.67	0.55	0.47
<b>Trading statistics</b> <sup>(1)</sup>										
TSX – C\$										
Trading volume (thousands)	<b>3,846,360</b>	3,025,819	3,394,111	3,067,445	3,137,743	3,732,827	1,808,025	1,612,508	1,176,845	1,307,454
Share Price (C\$/share)										
High	<b>49.20</b>	56.50	46.72	44.09	27.80	21.29	21.28	24.54	23.50	23.37
Low	<b>34.92</b>	40.02	33.57	27.10	14.34	4.90	15.01	15.06	17.95	10.64
Close	<b>46.49</b>	44.38	43.41	37.60	26.73	15.30	21.00	16.47	22.46	21.40
NYSE – US\$										
Trading volume (thousands)	<b>1,668,339</b>	1,310,294	1,205,733	1,511,444	1,591,210	2,116,244	1,359,393	1,593,943	1,216,016	1,784,439
Share Price (US\$/share)										
High	<b>35.12</b>	41.29	34.37	35.30	22.17	16.40	16.28	19.10	18.39	17.64
Low	<b>24.65</b>	29.23	24.41	21.16	11.20	3.36	11.29	10.93	13.77	7.30
Close	<b>33.85</b>	30.87	32.76	27.77	21.13	12.03	16.18	12.07	17.86	15.94
<b>RATIOS</b>										
Debt to book capitalization <sup>(5)</sup>	<b>26%</b>	32%	20%	22%	27%	40%	37%	39%	41%	39%
After-tax return on average capital employed <sup>(3)</sup>	<b>20%</b>	13%	17%	22%	16%	—%	11%	6%	6%	—%
Daily production before royalties per ten thousand common shares (BOE/d)	<b>7.5</b>	6.5	6.2	5.8	5.3	4.9	4.6	4.5	3.9	3.6
Total proved plus probable reserves per common share (BOE) <sup>(7)</sup>	<b>10.0</b>	9.6	8.6	8.2	7.3	6.7	6.0	5.6	4.9	4.2
Net asset value (\$/share) <sup>(1)(9)</sup>	<b>89.01</b>	94.53	87.40	82.28	59.68	35.81	48.55	50.95	40.70	37.38

(1) Updated to reflect the two for one common share split in June 2024.

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

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

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

(5) Capital Management Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

(6) On March 4, 2026, the Board of Directors approved a quarterly dividend of \$0.625 per common share, an increase from the previous quarterly dividend of \$0.5875 per common share. The dividend is payable on April 7, 2026. In 2022, the Company paid a special dividend of \$0.75 per common share.

(7) Based upon company gross reserves (forecast price and costs, before royalties), using year end common shares outstanding.

Years ended December 31	2025	2024	2023	2022	2021	2020	2019	2018	2017	2016
<b>COMPANY NET RESERVES</b> <sup>(8)(10)</sup>										
<b>Crude oil and NGLs</b> (MMbbl)										
Company net proved reserves (after royalties)										
North America	10,296	9,665	8,977	8,940	8,740	8,980	8,129	7,163	6,423	3,909
North Sea	—	6	8	11	79	96	109	119	120	134
Offshore Africa	39	48	53	59	64	70	70	72	70	74
	<b>10,335</b>	9,720	9,038	9,010	8,883	9,147	8,307	7,354	6,613	4,117
Company net proved plus probable reserves (after royalties)										
North America	12,671	11,990	11,240	11,181	10,883	11,151	10,231	9,456	8,353	6,015
North Sea	—	7	12	15	117	160	175	186	180	252
Offshore Africa	47	61	69	77	85	94	93	98	102	108
	<b>12,718</b>	12,058	11,322	11,273	11,085	11,405	10,499	9,740	8,635	6,375
<b>Natural gas</b> (Bcf)										
Company net proved reserves (after royalties)										
North America	15,954	14,849	12,952	11,614	11,076	8,373	5,795	6,005	6,032	5,845
North Sea	—	3	3	4	8	12	16	27	21	41
Offshore Africa	6	18	22	27	25	32	37	21	15	23
	<b>15,960</b>	14,871	12,977	11,645	11,109	8,417	5,849	6,053	6,068	5,909
Company net proved plus probable reserves (after royalties)										
North America	24,465	23,475	20,596	18,617	18,315	13,884	8,556	8,681	8,454	7,888
North Sea	—	5	5	7	11	17	21	38	32	85
Offshore Africa	9	30	36	40	39	48	52	44	47	55
	<b>24,473</b>	23,510	20,637	18,664	18,364	13,949	8,630	8,763	8,533	8,028
Total company net proved reserves (after royalties) (MMBOE)	<b>12,995</b>	12,198	11,201	10,951	10,734	10,549	9,282	8,363	7,625	5,102
Total company net proved plus probable reserves (after royalties) (MMBOE)	<b>16,797</b>	15,976	14,761	14,384	14,146	13,730	11,938	11,202	10,057	7,713
<b>OPERATING INFORMATION</b>										
<b>Daily production</b> (before royalties) <sup>(10)</sup>										
Crude oil and NGLs (Mbb/d)										
North America										
Exploration and Production	569	509	496	480	473	460	406	351	359	351
North America										
Oil Sands Mining and Upgrading	565	472	451	426	448	417	395	426	282	123
North Sea	8	12	13	13	18	23	28	24	23	24
Offshore Africa	3	13	13	14	14	17	21	20	20	26
	<b>1,146</b>	1,006	974	933	952	918	850	821	685	524
Natural gas (MMcf/d)										
North America	2,538	2,136	2,139	2,075	1,680	1,450	1,443	1,490	1,601	1,622
North Sea	3	2	2	2	3	12	24	32	39	38
Offshore Africa	6	9	10	13	12	15	24	26	22	31
	<b>2,547</b>	2,147	2,151	2,090	1,695	1,477	1,491	1,548	1,662	1,691
Total production (before royalties) (MBOE/d)	<b>1,571</b>	1,363	1,332	1,281	1,235	1,164	1,099	1,079	962	806
<b>PRODUCT PRICING</b> <sup>(11)</sup>										
Average crude oil & NGLs price (\$/bbl) <sup>(3)(12)</sup>	<b>71.54</b>	77.76	72.36	90.64	63.71	31.90	55.08	46.92	48.57	36.93
Average natural gas price (\$/Mcf)	<b>2.51</b>	1.86	3.10	6.55	4.07	2.40	2.34	2.61	2.76	2.32
Average SCO price (\$/bbl) <sup>(3)(13)</sup>	<b>86.41</b>	98.03	100.06	117.69	77.95	43.98	70.18	68.61	63.98	58.59

(8) Company net reserves are company gross reserves after royalties in accordance with NI 51-101. Reserves data may not add and BOE values may not calculate exactly due to rounding.

(9) Net present value, discounted at 10%, of the future net revenue (before income tax and excluding the ARO for existing development as at December 31, 2025) of the Company's total proved plus probable crude oil, natural gas and NGL reserves prepared using forecast prices and costs, as reported in the Company's AIF, plus the estimated market value of core unproved property at \$300/acre for 2025 to 2022 (\$285/acre from 2021 to 2016), less debt, divided by common shares outstanding. Debt for the purpose of this calculation is defined as long-term debt plus/minus the working capital deficit/surplus. Future development costs and abandonment and reclamation costs attributable to future development activity have been applied against the future net revenue.

(10) Numbers may not add due to rounding.

(11) Product prices reflect realized product prices before blending costs, transportation costs and exclude risk management activities.

(12) Average crude oil and NGLs pricing excludes SCO.

(13) For years 2017 to 2025, average SCO product price includes AOSP realized product prices net of blending and feedstock costs.

# Corporate Information

## Board of Directors

**\*Catherine M. Best**, F.C.A., ICD.D <sup>(1)(2)</sup>  
Corporate Director  
Calgary, Alberta

**\*Shelley A. M. Brown**, C.M., F.C.P.A., F.C.A., ICD.D <sup>(1)</sup>  
Corporate Director  
Saskatoon, Saskatchewan

**\*M. Elizabeth Cannon**, Ph.D, O.C. <sup>(3)(5)</sup>  
Corporate Director  
Calgary, Alberta

**N. Murray Edwards**, C.M.  
Corporate Director  
St. Moritz, Switzerland

**\*Christopher L. Fong** <sup>(3)(5)</sup>  
Corporate Director  
Calgary, Alberta

**\*Ambassador Gordon D. Giffin** <sup>(1)(4)(6)</sup>  
Partner and Global Vice Chair, emeritus, Dentons US LLP  
Sarasota, Florida

**\*Wilfred A. Gobert** <sup>(1)(2)(4)</sup>  
Corporate Director  
Calgary, Alberta

**\*Christine M. Healy** <sup>(1)(4)</sup>  
President and CEO, Northland Power Inc.  
Toronto, Ontario

**\*Steve W. Laut** <sup>(3)(5)</sup>  
Corporate Director  
Calgary, Alberta

**\*Honourable Frank J. McKenna**, P.C., O.C., O.N.B., K.C. <sup>(2)(4)</sup>  
Deputy Chair, TD Bank Group  
Cap Pelé, New Brunswick

**Scott G. Stauth** <sup>(3)</sup>  
President, Canadian Natural Resources Limited  
Calgary, Alberta

**\*David A. Tuer** <sup>(1)(5)</sup>  
Corporate Director  
Calgary, Alberta

**\*Annette M. Verschuren**, O.C. <sup>(2)(3)</sup>  
Chairman and Chief Executive Officer, NRStor Inc.  
Toronto, Ontario

(1) Audit Committee member

(2) Compensation Committee member

(3) Health, Safety, Asset Integrity and Environmental Committee member

(4) Nominating, Governance and Risk Committee member

(5) Reserves Committee member

(6) Lead Independent Director

\*Determined to be independent by the Nominating, Governance and Risk Committee of the Board of Directors and pursuant to the independent standards established under National Instrument 58-101 and the New York Stock Exchange Corporate Governance Listing Standards.

## Senior Officers

**N. Murray Edwards**  
Executive Chairman

**Scott G. Stauth**  
President

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

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

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

**Victor C. Darel**  
Chief Financial Officer

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

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

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

**Dean W. Halewich**  
Senior Vice-President, Safety, Risk Management  
and Innovation

**Sheryl L. Kapeluck**  
Senior Vice-President, Finance

**Devin C. Lowe**  
Senior Vice-President, Exploitation

**Warren P. Raczynski**  
Senior Vice-President, Thermal

**Kara L. Slemko**  
Senior Vice-President, Commercial Operations and  
Corporate Development

**Trevor T. Wagil**  
Senior Vice-President, Oil Sands Mining and Upgrading

**Brenda G. Balog**  
Vice-President, Legal and General Counsel

**Erin L. Lunn**  
Vice-President, Land

**Mark A. Overwater**  
Vice-President, Marketing

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

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

## HEAD OFFICE

### Canadian Natural Resources Limited

2100, 855 – 2 Street S.W. <sup>(1)</sup>

Calgary, Alberta T2P 4J8

**Telephone:** (403) 517-6700

**Facsimile:** (403) 517-7350

**Website:** www.cnrl.com

## INVESTOR RELATIONS

**Telephone:** (403) 514-7777

**Email:** ir@cnrl.com

## INTERNATIONAL OFFICE

### CNR International (U.K.) Limited

St. Magnus House, Guild Street

Aberdeen AB11 6NJ Scotland

## REGISTRAR AND TRANSFER AGENT

### Computershare Trust Company of Canada

Calgary, Alberta

Toronto, Ontario

### Computershare Investor Services LLC

New York, New York

## AUDITORS

### PricewaterhouseCoopers LLP

Calgary, Alberta

## INDEPENDENT QUALIFIED RESERVES EVALUATORS

### GLJ Ltd.

Calgary, Alberta

### Sroule International Limited

Calgary, Alberta

## STOCK LISTING – CNO

Toronto Stock Exchange

The New York Stock Exchange

(1) In June 2026, the Company is relocating its head and registered office to 400 - 4th Avenue S.W., Calgary, AB, T2P 0J4.

## CORPORATE GOVERNANCE

Canadian Natural's corporate governance practices and disclosure of those practices are in compliance with National Policy 58-201 Corporate Governance Guidelines and National Instrument 58-101 Disclosure of Corporate Governance Practices. Canadian Natural, as a foreign private issuer in the United States, may rely on home jurisdiction listing standards for compliance with most of the New York Stock Exchange (NYSE) Corporate Governance Listing Standards but must disclose any significant differences between its corporate governance practices and those required for U.S. companies listed on the NYSE.

Canadian Natural follows Toronto Stock Exchange (TSX) rules with respect to shareholder approval of equity compensation plans and material revisions to such plans. TSX rules provide that only the creation of or material amendments to equity compensation plans which provide for new issuance of securities are subject to shareholder approval. However, the NYSE requires shareholder approval of all equity compensation plans whether they provide for the delivery of newly issued securities, or rely on securities acquired in the open market by the issuing company for the purposes of redistribution to plan beneficiaries, and material revisions to such plans. Canadian Natural has a performance share unit plan pursuant to which common shares are purchased through the TSX. This is not a new issue of securities under the performance share unit plan and under TSX rules the plan is not subject to shareholder approval.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2025 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying as to disclosure controls and procedures and internal control over financial reporting.

## COMPANY DEFINITION

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our", "Canadian Natural", or the "Company".

## CURRENCY

All amounts are reported in Canadian currency unless otherwise stated.

## ABBREVIATIONS

Abbreviations can be found on page 11.

## METRIC CONVERSION CHART

To Convert	To	Multiply by
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

## COMMON SHARE DIVIDEND

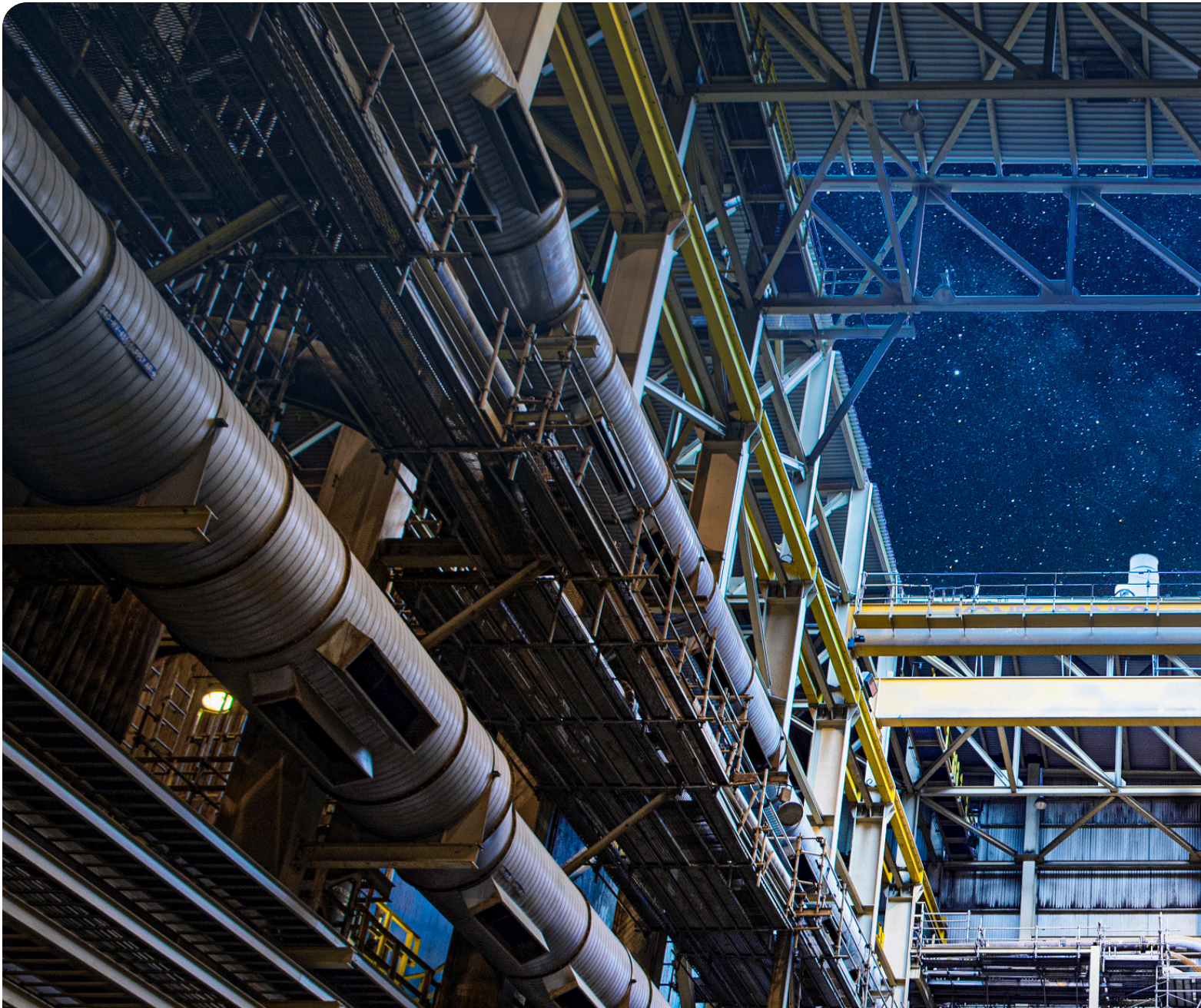
The Company paid its first dividend on its common shares on April 1, 2001. Since then, dividends have been paid quarterly.

The following table shows the aggregate amount of the cash dividends declared per common share of the Company and accrued in each of its last three years ended December 31, 2025 and is restated for the two for one subdivision of the common shares which occurred in June 2024.

	2025	2024	2023
Cash dividends declared per common share	\$2.35	\$2.14	1.85

## NOTICE OF ANNUAL MEETING

Canadian Natural's 2026 Annual Meeting of the Shareholders will be held on Thursday, May 7, 2026 at 11:00 a.m. Mountain Daylight Time in Macleod Hall CD of the Telus Convention Centre, Calgary, Alberta.



**Canadian Natural**

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