PRESS RELEASE

TSX & NYSE: CNQ

CANADIAN NATURAL RESOURCES LIMITED ANNOUNCES 2025 FOURTH QUARTER AND YEAR END RESULTS
CALGARY, ALBERTA – MARCH 5, 2026 – FOR IMMEDIATE RELEASE

Canadian Natural's President, Scott Stauth, commented on the Company's fourth quarter and year end 2025 results, "The year 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, 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. As a result, we achieved record annual production of 1,571 MBOE/d in 2025, resulting in year-over-year 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, which are not subject to widening heavy crude oil differentials.

Strong execution across our large, diverse asset base continues to provide significant opportunities to create shareholder value in 2026 and beyond. This is evident by our increased production, strong free cash flow and growth in reserves achieved in 2025, through 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, we are decreasing our 2026 operating capital forecast by approximately $310 million, following the completion of a strategic acquisition early in 2026, and increasing 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.

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."

Canadian Natural's Chief Financial Officer, Victor Darel, added "In 2025, we generated adjusted net earnings 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. 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 approved an approximate 6.4% increase to our quarterly dividend, bringing the annualized dividend up to $2.50 per common share. This marks 2026 as the 26th 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% and Debt to Adjusted EBITDA at 0.7x."

2025 ANNUAL HIGHLIGHTS

- Generated net earnings of approximately $10.8 billion and adjusted net earnings from operations of $7.4 billion.
- Generated adjusted funds flow of approximately $15.5 billion.
- Returns to shareholders totaled approximately $9.0 billion, comprised of $4.9 billion in dividends, $1.4 billion in share repurchases and $2.7 billion through reduction in the Company's net debt.
  - Approximately 33.5 million common shares were repurchased and cancelled in 2025 at a weighted average price of $43.28 per share.
- Record total annual production of approximately 1,571,000 BOE/d, an increase of 207,000 BOE/d or 15% from 2024 levels.
  - Record total liquids production of approximately 1,146,000 bbl/d, an increase of 141,000 bbl/d or 14% from 2024 levels.
    - Strong total corporate liquids operating costs(1) of $18.44/bbl (US$13.19/bbl), compared to $18.56/bbl (US$13.55/bbl) in 2024.
    - Record Oil Sands Mining and Upgrading production of approximately 565,000 bbl/d of zero decline SCO, with upgrader utilization of 100%, including the planned turnaround at the Athabasca Oil Sands Project ("AOSP").
      - Industry leading Oil Sands Mining and Upgrading operating costs of $22.66/bbl (US$16.21/bbl), compared to $22.88/bbl (US$16.70/bbl) in 2024.
    - Record thermal in situ production of 275,000 bbl/d of long life low decline production.
  - Record natural gas production of 2,547 MMcf/d, an increase of 400 MMcf/d or 19% from 2024 levels.
- Canadian Natural reduced net debt by approximately $2.7 billion from 2024 year end levels.
  - Repaid US$1.2 billion of US dollar debt securities.
  - Issued C$1.65 billion in 3, 5 and 10 year medium-term notes.

2025 FOURTH QUARTER HIGHLIGHTS

- Generated net earnings of approximately $5.3 billion and adjusted net earnings from operations of $1.7 billion.
- Generated adjusted funds flow of approximately $3.7 billion.
- Returns to shareholders totaled approximately $2.7 billion, comprised of $1.2 billion in dividends, $0.3 billion in share repurchases and $1.2 billion through reduction in the Company's net debt.
- Record total quarterly production of approximately 1,659,000 BOE/d, an increase of 188,000 BOE/d or 13% from Q4/24 levels.
  - Record total liquids production of approximately 1,215,000 bbl/d, an increase of 125,000 bbl/d or 12% from Q4/24 levels.
    - Record Oil Sands Mining and Upgrading production of approximately 620,000 bbl/d of zero decline SCO with upgrader utilization of 105%.
      - Industry leading Oil Sands Mining and Upgrading operating costs of $21.84/bbl (US$15.66/bbl).
- On November 1, 2025, Canadian Natural closed the AOSP asset swap with Shell and now owns and operates 100% of the Albian oil sands mines and associated reserves.
  - The transaction added approximately 31,000 bbl/d of annual, zero decline bitumen production to our Oil Sands Mining and Upgrading portfolio.

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

ACCELERATING SHAREHOLDER RETURNS WITH REVISED FREE CASH FLOW ALLOCATION POLICY

As a result of the Company's continued strong execution and resilience to volatile commodity prices, combined with continued growth of production, cash flow and reserves through strategic acquisitions and organic development, Canadian Natural is increasing its annual dividend and enhancing direct shareholder returns by updating its net debt targets within the Company's free cash flow allocation policy. The policy was last adjusted in October 2024, when on a proforma basis, including the acquired Chevron assets, annual production was approximately 1,465,000 BOE/d. Since then, through organic growth and strategic acquisitions, annual production has grown by approximately 12% or 175,000 BOE/d, to the mid-point of updated 2026 guidance.

- The Board of Directors have approved an approximate 6.4% increase to the quarterly cash dividend to $0.625 per common share, from $0.5875 per common share, payable on April 7, 2026 to shareholders of record at the close of business on March 20, 2026.
  - This dividend increase represents an annualized dividend of $2.50 per common share and demonstrates the confidence that the Board has in the sustainability of our business model, our strong balance sheet and the strength of our diverse, long life low decline reserves and asset base.
    - Canadian Natural's leading track record of 26 consecutive years of dividend growth continues with a CAGR of 20% over that time.
- The Company's free cash flow allocation policy has been revised based upon the increase in the Company's reserves and production from when it was last reviewed in 2024.
  - When net debt is at or above $16 billion (formerly $15 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 (formerly $12 billion) and $16 billion (formerly $15 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 (formerly $12 billion), 100% of free cash flow will be allocated to direct shareholder returns in the form of share repurchases.
  - 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.
  - Free cash flow is calculated as adjusted funds flow less dividends on common shares, net capital expenditures and abandonment expenditures.
- On March 4, 2026, the Board of Directors approved the renewal of the Company's Normal Course Issuer Bid ("NCIB"), which states that during the 12 month period commencing on March 13, 2026 and ending on March 12, 2027, the Company can repurchase for cancellation up to 10% of the public float (as determined in accordance with the rules of the TSX), subject to TSX approval.

UPDATED 2026 GUIDANCE

- Canadian Natural is utilizing its capital flexibility in 2026 by reducing forecasted Operating Capital Expenditures by approximately $310 million, which reflects continuous improvement and efficiency gains on our development program and a deferral of front-end engineering and design ("FEED") capital on our Jackpine mine expansion opportunity at Albian.
  - As first communicated at the Company's 2025 investor day held on November 7, 2025, Canadian Natural continues to progress on its budgeted defined short-term growth strategy through the development of its Conventional E&P assets and thermal drill to fill pad additions, and its medium-term growth strategy by expending FEED capital on both its 70,000 bbl/d Pike 2 growth project and 30,000 bbl/d Jackfish expansion project.
  - As a part of its long-term growth strategy, the Company is deferring FEED and defined capital for our Oil Sands Jackpine mine expansion opportunity at Albian, that was originally included in our 2026 capital budget. This approximately $8.25 billion project is being deferred due to the lack of finalization of government regulatory policies as it relates to carbon pricing and methane, which creates uncertainty and economic burden for long-term growth investments. Once there is more certainty on these regulatory policies, approval timelines and egress, we will reassess the viability of this project.
  - Additionally, subsequent to year end, Canadian Natural has acquired assets in the Peace River area of Alberta, which are adjacent to existing operations in the area, and elsewhere for approximately $765 million.
  - As a result, forecasted annual capital is being updated as follows:

Capital Expenditures[1] ($ millions)	2026 Budget	**2026 Updated Forecast**	Change
Conventional E&P	$ 3,320	**$ 3,160**	$ (160)
Thermal and Oil Sands Mining & Upgrading	$ 2,980	**$ 2,830**	$ (150)
Total Operating Capital Expenditures	$ 6,300	**$ 5,990**	$ (310)
Carbon Capture	$ 125	**$ 125**	$ —
Net acquisitions	$ —	**$ 765**	$ 765
Total Capital Expenditures	$ 6,425	**$ 6,880**	$ 455

(1) Forward-looking Non-GAAP Financial Measure. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A for the three months and year ended December 31, 2025 dated March 4, 2026 ("MD&A").

Note: 2026 capital expenditures excludes approximately $993 million of abandonment expenditures, before recoveries, related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea.

- Following the recent acquisition, Canadian Natural is increasing its 2026 production guidance range to 1,615 MBOE/d and 1,665 MBOE/d, with the mid-point being 20 MBOE/d higher than the budget.

Production Guidance[1] (before royalties)	2026 Budget	**2026 Updated Forecast**
Natural Gas (MMcf/d)	2,477 - 2,577	**2,560 - 2,615**
Conventional E&P Crude Oil & NGLs (Mbbl/d)	325 - 337	**336 - 346**
Thermal and Oil Sands Mining & Upgrading (Mbbl/d)	852 - 883	**852 - 883**
Total Liquids (Mbbl/d)	1,177 - 1,220	**1,188 - 1,229**
Total MBOE/d	1,590 - 1,650	**1,615 - 1,665**

(1) Reflects planned downtime for turnaround activities in all areas.

Note: Rounded to the nearest 1,000 bbl/d.

HIGHLIGHTS

($ millions, except per common share amounts)		Three Months Ended Dec 31 2025	Sep 30 2025	Dec 31 2024	Year Ended Dec 31 2025	Dec 31 2024
Net earnings		**$ 5,303**	$ 600	$ 1,138	**$ 10,820**	$ 6,106
Per common share	– basic	**$ 2.55**	$ 0.29	$ 0.54	**$ 5.17**	$ 2.87
	– diluted	**$ 2.54**	$ 0.29	$ 0.54	**$ 5.16**	$ 2.85
Adjusted net earnings from operations (1)		**$ 1,711**	$ 1,801	$ 1,977	**$ 7,444**	$ 7,414
Per common share	– basic (2)	**$ 0.82**	$ 0.86	$ 0.94	**$ 3.56**	$ 3.49
	– diluted (2)	**$ 0.82**	$ 0.86	$ 0.93	**$ 3.55**	$ 3.46
Cash flows from operating activities		**$ 3,768**	$ 3,940	$ 3,432	**$ 15,106**	$ 13,386
Adjusted funds flow (1)		**$ 3,748**	$ 3,920	$ 4,186	**$ 15,460**	$ 14,859
Per common share	– basic (2)	**$ 1.80**	$ 1.88	$ 1.99	**$ 7.39**	$ 6.99
	– diluted (2)	**$ 1.79**	$ 1.87	$ 1.97	**$ 7.37**	$ 6.94
Cash flows used in investing activities		**$ 1,200**	$ 2,234	$ 10,414	**$ 6,687**	$ 14,095
Net capital expenditures (1)		**$ 1,237**	$ 2,124	$ 10,348	**$ 6,579**	$ 14,431
Net capital expenditures (1), excluding net acquisitions (3)		**$ 1,413**	$ 1,318	$ 1,290	**$ 5,707**	$ 5,286
Abandonment expenditures		**$ 201**	$ 189	$ 151	**$ 771**	$ 646
Daily production, before royalties						
Natural gas (MMcf/d)		**2,660**	2,668	2,283	**2,547**	2,147
Crude oil and NGLs (bbl/d)		**1,215,364**	1,175,604	1,090,002	**1,146,175**	1,005,603
Equivalent production (BOE/d) (4)		**1,658,681**	1,620,261	1,470,428	**1,570,757**	1,363,496

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

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

(3) Includes the impact of cash paid and received related to acquisitions and dispositions. The Company received net cash consideration of $212 million related to the AOSP asset swap in Q4/25. Refer to the 'Net Capital Expenditures' table in the Company's MD&A.

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

- Net earnings of approximately $10.8 billion in 2025 reflected strong operational performance, as well as the impact of non-cash accounting gains on the AOSP asset swap that closed in Q4/25, together with non-cash recoverability charges related to the North Sea and Offshore Africa. These items are discussed in detail in the Q4/25 Financial Statements and MD&A.
  - Adjusted net earnings from operations was strong at $7.4 billion in 2025.

RESERVES HIGHLIGHTS

A key differentiator for Canadian Natural is the strength, diversity and balance of its world class, top tier assets. The Company's total proved reserve life index ("RLI")[(1)] of 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 Company's reserves were evaluated and reviewed by Independent Qualified Reserves Evaluators ("IQREs"). The following highlights are based on the Company's reserves using forecast prices and costs at December 31, 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 Finding, Development and Acquisition ("FD&A") costs:
  - FD&A costs, including changes in Future Development Cost ("FDC"), are $3.64/BOE for total proved reserves and $2.42/BOE for total proved plus probable reserves.
- The net present value of future net revenues, before income tax, discounted at 10%, is $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 '2025 Year End Reserves' section of this document.

OPERATIONS REVIEW

North America Oil Sands Mining and Upgrading

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Synthetic crude oil production (bbl/d) (1)(2)	**619,901**	581,136	534,631	**565,102**	472,245

(1) SCO production before royalties and excludes production volumes consumed internally as diesel.
(2) Consists of heavy and light synthetic crude oil products.

- Oil Sands Mining and Upgrading achieved record annual production in 2025, averaging 565,102 bbl/d of SCO, an increase of 20% or approximately 93,000 bbl/d from 2024 levels, reflecting the additional working interests acquired in AOSP, combined with effective and efficient operations.
  - Oil Sands Mining and Upgrading achieved strong annual upgrader utilization, averaging 100% in 2025, which included a planned turnaround at AOSP.
  - Industry leading Oil Sands Mining and Upgrading operating costs averaged $22.66/bbl (US$16.21/bbl) of SCO in 2025, compared to $22.88/bbl (US$16.70/bbl) in 2024.
  - Oil Sands Mining and Upgrading production has strong realized pricing, averaging $86.41/bbl in 2025.
- At Horizon, the Company is progressing its Naphtha Recovery Unit Tailings Treatment ("NRUTT") project which targets incremental production of approximately 6,300 bbl/d of SCO, following mechanical completion in Q3/27.
- As a part of its long-term growth strategy, the Company is deferring FEED and defined capital for our Oil Sands Jackpine mine expansion opportunity at Albian, that was originally included in our 2026 capital budget. This approximately $8.25 billion project is being deferred due to the lack of finalization of government regulatory policies as it relates to carbon pricing and methane, which creates uncertainty and economic burden for long-term growth investments. Once there is more certainty on these regulatory policies, approval timelines and egress, we will reassess the viability of this project.

North America Exploration and Production

Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Bitumen production (bbl/d)	**266,308**	274,752	276,231	**275,086**	271,011
Net bitumen wells drilled	**25**	11	16	**78**	94
Net successful bitumen wells drilled	**24**	11	16	**77**	94
Success rate	**96%**	100%	100%	**99%**	100%

- Thermal in situ achieved record annual production in 2025, averaging 275,086 bbl/d, an increase of 2% from 2024 levels, reflecting the Company's capital efficient pad add and development program, partially offset by natural field declines.
  - Thermal in situ operating costs remain strong, averaging $11.09/bbl (US$7.93/bbl) in 2025, comparable to 2024 levels.
- As part of the Company's defined short-term growth strategy, Canadian Natural has decades of robust capital efficient drill to fill growth opportunities on its long life low decline thermal in situ assets, which we continue to develop in a disciplined manner to deliver safe and reliable thermal in situ production.
  - The first Pike 1 pad was brought on production ahead of schedule in December 2025 which is tied into the Jackfish 3 facility. Current production rates from this pad of approximately 27,000 bbl/d are exceeding expectations, with a Steam to Oil Ratio ("SOR") of approximately 1.8x. A second Pike 1 pad is targeted to come on production in April 2026 and is targeted to keep production at the Jackfish 3 facility at full capacity.
  - At Primrose, the Company completed drilling a Cyclic Steam Stimulation ("CSS") pad in February 2026, with production targeted to come on in Q3/26. The Company is drilling two additional CSS pads which are targeted to come on production in 2027.
  - At Kirby, the Company is planning to commence drilling a Steam Assisted Gravity Drainage ("SAGD") pad in Q2/26, which is targeted to come on production in 2027.

- As part of the Company's defined medium-term growth strategy, in 2026, front end engineering is progressing on both its 70,000 bbl/d Pike 2 growth project and 30,000 bbl/d Jackfish expansion project. In December 2025, Canadian Natural received regulatory approval for the Pike 2 SAGD project.
- Canadian Natural has been piloting solvent enhanced oil recovery technology on certain thermal in situ assets with an objective to increase bitumen production while reducing the SOR and Greenhouse Gas ("GHG") emissions, at the same time optimizing solvent recovery. This technology has the potential for application throughout the Company's extensive thermal in situ asset base.
    - The Company continues to operate the commercial scale solvent SAGD pad at Kirby North and the solvent enhanced steam flood pilot at Primrose. An additional solvent SAGD pilot at Kirby South is targeted to begin injection in Q2/26 to evaluate additional future commercial development opportunities.

Crude oil and NGLs – excluding Thermal In Situ Oil Sands

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil and NGLs production (bbl/d)	**319,189**	309,873	255,729	**294,315**	238,277
Net crude oil wells drilled	**90**	78	84	**282**	214
Net successful crude oil wells drilled	**90**	78	84	**281**	213
Success rate	**100%**	100%	100%	**99%**	99%

- North America E&P liquids production, excluding thermal in situ, averaged 294,315 bbl/d in 2025, an increase of 24% or approximately 56,000 bbl/d from 2024 levels, reflecting opportunistic acquisitions and strong organic growth from heavy crude oil multilaterals, light crude oil and liquids-rich natural gas.
    - Primary heavy crude oil production averaged 87,888 bbl/d in 2025, an increase of 11% from 2024 levels, reflecting strong drilling results from the Company's multilateral wells.
        - Canadian Natural's highly successful multilateral drilling program continues to unlock opportunity on our 3 million net acres of high quality land throughout our primary heavy crude oil assets.
        - Operating costs in the Company's primary heavy crude oil operations averaged $16.68/bbl (US$11.93/bbl) in 2025, a decrease of 8% from 2024 levels, primarily reflecting lower operating cost multilateral production.
    - Pelican Lake production averaged 42,470 bbl/d in 2025, a decrease of 5% from 2024 levels, reflecting the low natural field declines from this long life low decline asset.
        - Operating costs at Pelican Lake averaged $9.24/bbl (US$6.61/bbl) in 2025, comparable to 2024 levels.
    - North America light crude oil and NGLs production averaged 163,957 bbl/d in 2025, an increase of 43% or approximately 50,000 bbl/d from 2024 levels, primarily reflecting opportunistic acquisitions and strong drilling results.
        - Operating costs in the Company's North America light crude oil and NGLs operations averaged $12.39/bbl (US$8.87/bbl) in 2025, a decrease of 9% from 2024 levels, primarily reflecting higher production volumes.

North America Natural Gas

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Natural gas production (MMcf/d)	**2,657**	2,658	2,273	**2,538**	2,136
Net natural gas wells drilled	**20**	17	14	**78**	79
Net successful natural gas wells drilled	**20**	17	14	**78**	78
Success rate	**100%**	100%	100%	**100%**	99%

- Record North America natural gas production was achieved in 2025, averaging 2,538 MMcf/d, an increase of 19% from 2024 levels, primarily reflecting opportunistic acquisitions and strong drilling results in the Company's liquids-rich natural gas assets.
    - North America natural gas operating costs averaged $1.11/Mcf in 2025, a decrease of 7% from 2024 levels, primarily reflecting higher production volumes and cost efficiencies.

International Exploration and Production

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Crude oil production (bbl/d)	**9,966**	9,843	23,411	**11,672**	24,070
Natural gas production (MMcf/d)	**3**	10	10	**9**	11

- International E&P crude oil production volumes averaged 11,672 bbl/d in 2025, a decrease of 52% compared to 2024 levels. The decrease reflects temporary suspension of production at Baobab in Offshore Africa due to the planned refurbishment of its floating production storage and offloading ("FPSO") vessel which is expected to return to service in Q2/26, planned decommissioning activities in the North Sea and natural field declines.

Drilling Activity

	Year Ended			
	December 31, 2025		December 31, 2024	
(number of wells)	**Gross**	**Net**	Gross	Net
Crude oil [(1)]	**368**	**358**	313	307
Natural gas	**99**	**78**	94	78
Dry	**2**	**2**	2	2
Subtotal	**469**	**438**	409	387
Stratigraphic test / service wells	**522**	**499**	474	407
Total	**991**	**937**	883	794
Success rate (excluding stratigraphic test / service wells)		**99%**		99%

(1) Includes bitumen wells.

- Canadian Natural drilled a total of 438 net crude oil and natural gas wells in 2025, 51 more than in 2024.

MARKETING

	Three Months Ended			Year Ended	
	Dec 31 2025	Sep 30 2025	Dec 31 2024	**Dec 31 2025**	Dec 31 2024
Benchmark Commodity Prices					
WTI benchmark price (US$/bbl) [1]	**$ 59.13**	$ 64.95	$ 70.27	**$ 64.77**	$ 75.72
WCS heavy differential (discount) to WTI (US$/bbl) [1]	**$ (11.20)**	$ (10.36)	$ (12.55)	**$ (11.10)**	$ (14.73)
WCS heavy differential as a percentage of WTI (%) [1]	**19%**	16%	18%	**17%**	19%
Condensate benchmark price (US$/bbl)	**$ 57.01**	$ 63.12	$ 70.66	**$ 63.32**	$ 72.94
SCO price (US$/bbl) [1]	**$ 57.78**	$ 66.26	$ 71.13	**$ 64.42**	$ 75.09
SCO premium (discount) to WTI (US$/bbl) [1]	**$ (1.35)**	$ 1.31	$ 0.86	**$ (0.35)**	$ (0.63)
AECO benchmark price (C$/GJ)	**$ 2.22**	$ 0.94	$ 1.38	**$ 1.76**	$ 1.36
Realized Prices					
Exploration & Production liquids realized price (C$/bbl) [2][3][4][5]	**$ 64.42**	$ 72.57	$ 75.22	**$ 71.54**	$ 77.76
SCO realized price (C$/bbl) [1][3][4][5]	**$ 75.90**	$ 87.85	$ 95.08	**$ 86.41**	$ 98.03
Natural gas realized price (C$/Mcf) [4]	**$ 2.89**	$ 1.49	$ 2.02	**$ 2.51**	$ 1.86

(1) West Texas Intermediate ("WTI"); Western Canadian Select ("WCS"); Synthetic Crude Oil ("SCO").
(2) Exploration & Production crude oil and NGLs average realized price excludes SCO.
(3) Pricing is net of blending and feedstock costs.
(4) Excludes risk management activities.
(5) Non-GAAP ratio. Refer to the 'Non-GAAP and Other Financial Measures' section of the Company's MD&A.

- Canadian Natural has a balanced and diverse product mix of SCO, light crude oil, NGLs, heavy crude oil, bitumen and natural gas, complemented with a balanced and diverse marketing strategy.
- Canadian Natural has total contracted crude oil transportation capacity of 256,500 bbl/d, consisting of committed volumes to Canada’s west coast and to the United States Gulf Coast, being approximately 21% of 2026 forecasted liquids production. The egress supports Canadian Natural’s long-term sales strategy by targeting diverse refining markets which drive stronger netbacks while also reducing exposure to egress constraints.
- The North West Redwater refinery, 50% owned by the Company, primarily utilizes bitumen as feedstock, with production of ultra-low sulphur diesel and other refined products averaging 68,139 bbl/d in 2025.
- Canadian Natural has a diversified natural gas marketing strategy with the Company in 2026 to consume the equivalent of approximately 31% of forecasted natural gas production in its Oil Sands Mining and Upgrading and thermal operations, with approximately 37% targeted to be sold at AECO/Station 2 pricing, and approximately 32% targeted to be exported to other North American and international markets capturing higher natural gas prices, maximizing value.
- Canadian Natural has a long-term natural gas supply agreement with Cheniere Energy, Inc. ("Cheniere") as part of the Sabine Pass Liquefaction Expansion Project where the Company has agreed to sell 140,000 MMBtu/d of natural gas to Cheniere for a term of 15 years, with delivery anticipated to begin in 2030.
  - Under the terms of the agreement, Canadian Natural will deliver natural gas to Cheniere in Chicago and receive a Japan Korea Marker ("JKM") index price less deductions for transportation and liquefaction.

2025 YEAR END RESERVES

Determination of Reserves

For the year ended December 31, 2025, the Company retained IQREs, Sproule International Limited and GLJ Ltd., to evaluate and review all of the Company's proved and proved plus probable reserves. The evaluation and review was conducted and prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook. The reserves disclosure is presented in accordance with NI 51-101 requirements using forecast prices and escalated costs.

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

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

Summary of Company Gross Reserves

As of December 31, 2025
Forecast Prices and Costs

	Light and Medium Crude Oil (MMbbl)	Primary Heavy Crude Oil (MMbbl)	Pelican Lake Heavy Crude Oil (MMbbl)	Thermal Bitumen (MMbbl)	Mining Bitumen (MMbbl)	Synthetic Crude Oil (MMbbl)	Natural Gas (Bcf)	Natural Gas Liquids (MMbbl)	Barrels of Oil Equivalent (MMBOE)
Total Company									
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
Total Proved	309	228	243	3,330	849	7,134	18,006	817	15,910
Probable	118	105	107	1,845	46	554	9,969	404	4,840
Total Proved plus Probable	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 Independent Qualified Reserves Evaluators in the reserves estimates are the 3-Consultant-Average of price forecasts developed by Sproule International Limited, GLJ Ltd. and McDaniel & Associates Consultants Ltd., dated December 31, 2025:

		2026	2027	2028	2029	2030
Crude Oil and NGLs						
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
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 costs.
10. Abandonment, decommissioning and reclamation ("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.

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Special Note Regarding Forward-Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words "believe", "anticipate", "expect", "plan", "estimate", "target", "focus", "continue", "could", "intend", "may", "potential", "predict", "should", "will", "objective", "project", "forecast", "goal", "guidance", "outlook", "effort", "seeks", "schedule", "proposed", "aspiration", or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to the Company's strategy or strategic focus, capital budget, expected future commodity pricing, forecast or anticipated production volumes, royalties, production expenses, capital expenditures, forecast and anticipated abandonment expenditures, income tax expenses, and other targets provided throughout this Management's Discussion and Analysis ("MD&A") of the financial condition and results of operations of the Company, including the strength of the Company's balance sheet, the sources and adequacy of the Company's liquidity, and the flexibility of the Company's capital structure, constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including, without limitation, those in relation to: the Company's assets at Horizon Oil Sands ("Horizon"), the Athabasca Oil Sands Project ("AOSP"), the Primrose thermal oil projects ("Primrose"), the Pelican Lake water and polymer flood projects ("Pelican Lake"), the Kirby thermal oil sands project ("Kirby"), the Jackfish thermal oil sands project ("Jackfish") and the North West Redwater bitumen upgrader and refinery; construction by third parties of new, or expansion of existing, pipeline capacity or other means of transportation of bitumen, crude oil, natural gas, natural gas liquids ("NGLs"), or synthetic crude oil ("SCO") that the Company may be reliant upon to transport its products to market; the maintenance of the Company's facilities and any expected return to service dates; the construction, expansion, or maintenance of third-party facilities that process the Company's products; the abandonment and decommissioning of certain assets and the timing thereof; the development and deployment of technology and technological innovations; the financial capacity of the Company to complete its growth projects and responsibly and sustainably grow in the long-term; and the materiality of the impact of tax interpretations and litigation on the Company's results, also constitute forward-looking statements. These forward-looking statements are based on annual budgets and multi-year forecasts and are reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations, and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks. The reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives, or expectations upon which they are based will occur. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil, natural gas, and NGLs reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserves and production estimates.

The forward-looking statements are based on current expectations, estimates, and projections about the Company and the industry in which the Company operates, which speak only as of the earlier of the date such statements were made or as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance, or achievements of the Company to be materially different from any future results, performance, or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions (including as a result of the actions of the Organization of the Petroleum Exporting Countries Plus ("OPEC+"), the impact of conflicts in the Middle East, Ukraine and Venezuela, the impact of changes to US economic policy, increased inflation, and the risk of decreased economic activity resulting from a global recession) which may impact, among other things, demand and supply for and market prices of the Company's products, and the availability and cost of resources required by the Company's operations; volatility of and assumptions regarding crude oil, natural gas and NGLs prices; the impact of the ramp-up of LNG Canada on commodity prices; fluctuations in currency and interest rates; assumptions on which the Company's current targets are based; economic conditions in the countries and regions in which the Company conducts business; changes and uncertainties in the international trade environment, including with respect to tariffs, export restrictions, embargoes, and key trade agreements (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded); uncertainty in the regulatory framework governing greenhouse gas emissions including, among other things, financial and other support from various levels of government for climate related initiatives and potential emissions or production caps, and the implementation of the Memorandum of Understanding ("MOU") entered into between the Government of Canada and the Government of Alberta in November 2025; civil unrest and political uncertainty, including changes in government, actions of or against terrorists, insurgent groups, or other conflict including conflict between states; the ability of the Company to prevent and recover from a cyberattack, other cyber-related crime, and other cyber-related incidents; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition; the Company's defense of lawsuits; availability and cost of seismic, drilling, and other equipment; ability of the Company to complete capital programs; the Company's ability to secure adequate transportation for its products; unexpected disruptions or delays in the mining, extracting, or upgrading of the Company's bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the necessary labour required to build, maintain, and operate its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in the mining, extracting, or upgrading the Company's bitumen products; availability and cost of financing; the Company's success of exploration and development activities and its ability to replace and expand crude oil and natural gas reserves; the Company's ability to meet its targeted production levels; timing and success of integrating the business and operations of acquired companies and assets, including the acquisition of the remaining interest in the AOSP mines and other acquisitions that occurred in 2025; production levels; imprecision of reserves estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs not currently classified as proved; changes to future abandonment and decommissioning costs; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety, competition, environmental laws and regulations, and the impact of climate change initiatives on capital expenditures and production expenses); interpretations of applicable tax and competition laws and regulations; asset retirement obligations; the sufficiency of the Company's liquidity to support its growth strategy and to sustain its operations in the short-, medium-, and long-term; the strength of the Company's balance sheet; the flexibility of the Company's capital structure; the adequacy of the Company's provision for taxes; the impact of legal proceedings to which the Company is party; and other circumstances affecting revenues and expenses.

The Company's operations have been, and in the future may be, affected by political developments and by national, federal, provincial, state, and local laws and regulations such as restrictions on production, the imposition of tariffs, embargoes, or export restrictions on the Company's products (including uncertainties around US imposed tariffs, and actual or potential Canadian countermeasures, both of which continue to evolve and may be continued, suspended, increased, decreased, or expanded), changes in taxes, royalties and other amounts payable to governments or governmental agencies, price or gathering rate controls and environmental protection regulations (including the implementation of the MOU). Should one or more of these risks or uncertainties materialize, or should any of the Company's assumptions prove incorrect, actual results may vary in material respects from those projected in the forward-looking statements. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon its assessment of the future considering all information then available.

Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this document and the Company's 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 document or the Company's 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 Common Share Split and Comparative Figures

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

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

On June 20, 2024, amendments to the *Competition Act* (Canada) came into force with the adoption of Bill C-59, *An Act to Implement Certain Provisions of the Fall Economic Statement*, which impact environmental and climate disclosures by businesses. As a result of these amendments, certain public representations by a business regarding the benefits of the work it is doing to protect or restore the environment or mitigate the environmental and ecological causes or effects of climate change may violate the *Competition Act*'s deceptive marketing practices provisions. Subsequently, on November 4, 2025, the federal government tabled the 2025 Budget, which proposed further amendments to the *Competition Act*, namely removing the requirement that businesses substantiate their environmental representations about a business or business activity based on an internationally recognized methodology, and eliminating private rights of action under the revised business-activity greenwashing provision. Uncertainty surrounding the interpretation and enforcement of this legislation, which includes the status of any proposed or future amendments, may expose the Company to increased litigation and financial penalties, the outcome and impacts of which can be difficult to assess or quantify and may have a material adverse effect on the Company's business, reputation, financial condition, and results.

Special Note Regarding Currency, Financial Information and Production

This document should be read in conjunction with the Company's MD&A and unaudited interim consolidated financial statements (the "financial statements") for the three months and year ended December 31, 2025, and the Company's MD&A and audited consolidated financial statements for the year ended December 31, 2024. All dollar amounts are referenced in millions of Canadian dollars, except where noted otherwise. The Company's MD&A and financial statements for the three months and year ended December 31, 2025 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 document and the Company's 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 document and the Company's 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.

Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2024, is available on SEDAR+ at www.sedarplus.ca, and on EDGAR at www.sec.gov. Information in such Annual Information Form and on the Company's website does not form part of and is not incorporated by reference in the Company's MD&A, dated March 4, 2026.

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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 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 for the three months and year ended December 31, 2025 dated March 4, 2026.

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:

	Year Ended	
($ millions)	Dec 31 2025	Dec 31 2024
Adjusted funds flow (1)	$ 15,460	$ 14,859
Less: Dividends on common shares	4,871	4,429
Net capital expenditures (2)	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 MD&A for the three months and year ended December 31, 2025 dated March 4, 2026.

(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 MD&A for the three months and year ended December 31, 2025 dated March 4, 2026.

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.

Long-term Debt, net

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

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

Breakeven WTI Price

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

Capital Budget

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

Capital expenditures reflect forecasted net capital expenditures, before abandonment expenditures related to the execution of the Company's abandonment and reclamation programs in North America and the North Sea. The Company currently carries an Asset Retirement Obligation ("ARO") liability on its balance sheet for these 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 on related to tax recoveries in the North Sea.

Capital Efficiency

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

CONFERENCE CALL

Canadian Natural Resources Limited (TSX-CNQ / NYSE-CNQ) will be issuing its 2025 Fourth Quarter Earnings Results on Thursday, March 5, 2026 before market open.

A conference call will be held at 9:00 a.m. MT / 11:00 a.m. ET on Thursday, March 5, 2026.

Dial-in to the live event:

North America 1-800-717-1738 / International 001-289-514-5100.

Listen to the audio webcast:

Access the audio webcast on the home page of our website, www.cnrl.com.

Conference call playback:

North America 1-888-660-6264 / International 001-289-819-1325 (Passcode: 84285#)

Canadian Natural is a senior crude oil and natural gas production company, with continuing operations in its core areas located in Western Canada, the U.K. portion of the North Sea and Offshore Africa.

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