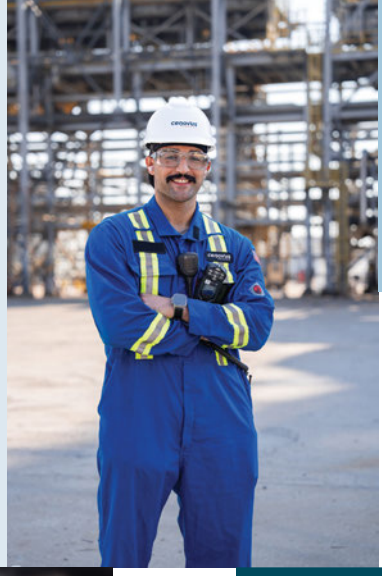
2025

ANNUAL REPORT

cenovus
ENERGY



At Cenovus, our purpose is to energize the world to make people's lives better.

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For additional information about forward-looking statements, specified financial measures and reserves contained in this Annual Report, see the Advisory on page 128.

ANNUAL HIGHLIGHTS

$8.9 billion
adjusted funds flow.[1]

$4 billion
free funds flow.[1]

$3.8 billion
returned to shareholders.

$8.2 billion
cash from operating activities.

Updated shareholder returns framework outlines targets for excess free funds flow to shareholders and deleveraging.

RECORD ANNUAL PRODUCTION

Total Upstream production:
834,200 BOE/d.

Total Oil Sands production:
644,100 BOE/d.

Value accretive MEG transaction adds over **100,000 bbls/d** of low-cost, long-life oil sands production.

Completed Narrows Lake and Foster Creek optimization projects, and **installed the West White Rose Platform.**

94%
U.S. Refining crude unit utilization.

103%
Record annual Canadian Refining crude unit utilization.

Since 2010, Cenovus has spent over **$6 billion** with Indigenous businesses.

In 2025, we announced an expansion to our Indigenous Housing Initiative (IHI), committing up to **$8 million** a year in our operating areas for new home construction meant to address the chronic housing shortage in Indigenous communities.

We've invested more than **$50 million** in the IHI since 2020, funding the building of approximately **200** homes.

1 *Non-GAAP financial measure. See Advisory*

Message from our President & Chief Executive Officer

Jon McKenzie

2025 was an outstanding year for the company, marked by disciplined execution and operational excellence. We advanced and completed major growth projects, acquired a top-tier oil sands asset, delivered record oil sands production and increased the profitability and competitiveness of our Downstream business.

The Narrows Lake tieback and Foster Creek optimization projects transitioned from construction to operations and successfully ramped up to deliver meaningful production. At West White Rose, we safely installed the concrete gravity structure and topsides in a first-of-its-kind operation offshore Newfoundland and Labrador and will be commencing drilling from the platform. The completion of these projects marks the end of a three-year investment cycle and we will continue ramping up volumes in 2026 while reducing growth spend.

Our acquisition of MEG Energy Corp. and its Christina Lake North asset added over 100,000 bbls/d of low-cost, long-life oil sands production. The investment extends Cenovus's resource base in the area and provides a platform to unlock additional barrels in both the near- and long-term as we integrate development of the broader Christina Lake area.

Additionally, we safely completed major turnarounds at Christina Lake, Sunrise, Liwan and Toledo on or ahead of schedule.

Safety remains our top value. We demonstrated solid safety performance in 2025 and we work to continuously improve, including building on our top-quartile process safety performance.

Our Oil Sands operations delivered another record year, with strong performance across all major assets. Numerous annual and quarterly production records were set at Foster Creek and Sunrise as well as for our total Oil Sands production. As a major shipper on pipelines to the west coast, U.S. Midwest and Gulf Coast, in tandem with our refining presence, we have substantially mitigated the risk of Canadian heavy oil dislocations and can access diversified markets, ensuring strong and resilient netbacks.

We continue to see stable, predictable output from our Asia Pacific assets offshore China and Indonesia, while the *SeaRose* floating production, storage and offloading vessel safely resumed production offshore Newfoundland and Labrador following a maintenance drydock to prepare it for new production from West White Rose.

Our Downstream operations ran reliably in 2025, with the Canadian Refining business setting multiple throughput and utilization records. The U.S. Refining business demonstrated improved performance across all key metrics in 2025 including reliability, cost and market capture. We streamlined our downstream portfolio, selling our 50% interest in the Wood River and Borger refineries, sharpening our focus on assets we control, that are core to our integrated heavy-oil value chain. The proceeds of $1.9 billion were used to bring down debt.

We remain committed to maintaining one of the strongest balance sheets in the sector. Our financial discipline positions us to be resilient at all points in the commodity price cycle, while giving us the flexibility to pursue and execute on strategic opportunities such as the MEG acquisition. We expect to see an inflection point in cash flow during 2026, as we continue to ramp up volumes from our growth projects and deliver on Christina Lake synergies.

In 2025, we returned $3.8 billion to our shareholders in the form of base and preferred share dividends, common share purchases and through preferred share redemptions.

Since 2021, the company's total shareholder returns have outperformed the S&P/TSX composite and energy indices by 126% and 30% respectively on a relative basis.

In 2026, we will further strengthen our heavy oil value chain – from the oil sands and conventional business to our midstream infrastructure to our upgrader and refineries – to enhance our competitiveness and remain responsive to market conditions. Downstream competitiveness will be a key focus as we build on the momentum achieved in 2025.

West White Rose and the Foster Creek amine claus sulphur unit will start operating this year, and implementation of the Cenovus operating model at Christina Lake North will continue to unlock additional value.

We will continue to work with governments toward policies that foster investment, growth and regulatory efficiency, while balancing environmental considerations. Meaningful progress on these fronts will be essential this year.

I want to thank our Board for its guidance, our staff and contractors for their commitment to safety and driving our operational excellence, and our investors for their ongoing confidence. Our diversified portfolio presents us with a long runway to drive sustainable growth, strengthen returns and continue delivering long-term value.

Management's Discussion and Analysis (unaudited)

For the year ended December 31, 2025
(Canadian dollars)

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This Management's Discussion and Analysis ("MD&A") for Cenovus Energy Inc. (which includes references to "we", "our", "us", "its", the "Company", or "Cenovus", and means Cenovus Energy Inc., the subsidiaries of, joint arrangements, and partnership interests held directly or indirectly by, Cenovus Energy Inc.) dated February 18, 2026, should be read in conjunction with our December 31, 2025 unaudited interim Consolidated Financial Statements and accompanying notes ("interim Consolidated Financial Statements") and our December 31, 2025 audited Consolidated Financial Statements and accompanying notes ("Consolidated Financial Statements"). All of the information and statements contained in this MD&A are made as at February 18, 2026, unless otherwise indicated. This MD&A contains forward-looking information about our current expectations, estimates, projections and assumptions. See the Advisory for information on the risk factors that could cause actual results to differ materially and the assumptions underlying our forward-looking information. Cenovus management ("Management") prepared the MD&A. The Audit Committee of the Cenovus Board of Directors ("the Board") reviewed and recommended the MD&A for approval by the Board, which occurred on February 18, 2026. Additional information about Cenovus, including our quarterly and annual reports, Annual Information Form ("AIF") and Form 40-F, is available on SEDAR+ at **sedarplus.ca**, on EDGAR at **sec.gov** and on our website at **cenovus.com**. Information on or connected to our website, even if referred to in this MD&A, does not constitute part of this MD&A.

Cenovus holds equity ownership interests in a number of joint ventures, as classified under IFRS Accounting Standards (as defined below), that are accounted for using the equity method in our Consolidated Financial Statements. Unless otherwise indicated, operational results of these joint ventures are not reflected in this MD&A. For further information, see the Advisory.

Basis of Presentation

This MD&A and the Consolidated Financial Statements were prepared in Canadian dollars (which includes references to "dollar" or "$"), except where another currency is indicated, and in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") (the "IFRS Accounting Standards"). Production volumes are presented on a before royalties basis. Refer to the Abbreviations and Definitions section for commonly used oil and gas terms.

OVERVIEW OF CENOVUS

We are a Canadian-based integrated energy company headquartered in Calgary, Alberta. We are one of the largest Canadian-based crude oil and natural gas producers, with upstream operations in Canada and the Asia Pacific region, and one of the largest Canadian-based refiners and upgraders, with downstream operations in Canada and the United States ("U.S.").

Our upstream operations include oil sands projects in northern Alberta; thermal and conventional crude oil, natural gas and natural gas liquids ("NGLs") projects across Western Canada; crude oil production offshore Newfoundland and Labrador; and natural gas and NGLs production offshore China and Indonesia. Our downstream operations include upgrading and refining operations in Canada and the U.S., and commercial fuel operations across Canada.

Our operations involve activities across the full value chain to develop, produce, refine, transport and market crude oil, natural gas and refined petroleum products in North America and internationally. Our physically and economically integrated upstream and downstream operations help us mitigate the impact of volatility in light-heavy crude oil price differentials and contribute to our net earnings by capturing value from crude oil, natural gas and NGLs production through to the sale of finished products such as transportation fuels.

For a description of our business segments, see the Reportable Segments section of this MD&A.

Our Strategy

At Cenovus, our purpose is to energize the world to make people's lives better. Our strategy is focused on maximizing shareholder value over the long-term through sustainable, low-cost, diversified and integrated energy leadership. Our five strategic objectives include: delivering top-tier safety performance and sustainability leadership; maximizing value through competitive cost structures and optimizing margins; a focus on financial discipline, including reaching and maintaining targeted debt levels while positioning Cenovus for resiliency through commodity price cycles; a disciplined approach to allocating capital to projects that generate returns at the bottom of the commodity price cycle; and absolute and per share free funds flow growth.

On December 11, 2025, we released our 2026 corporate guidance, which focused on disciplined capital allocation in support of increasing shareholder returns over time. We will continue to be focused on controlling costs, improving the profitability of our business and optimizing our advantaged portfolio to deliver value for our shareholders. For further details, see the Outlook section of this MD&A and our 2026 corporate guidance dated December 10, 2025, available on our website at cenovus.com.

YEAR IN REVIEW

Our 2025 results reflect strong operational performance in the upstream and downstream business. Despite a weakened commodity price environment, we delivered strong financial results, reached significant milestones in key growth projects and completed strategic acquisitions and divestitures, which enhance our asset portfolio.

- **Delivered safe and reliable operations.** We delivered safe operations across our business and safely completed turnarounds at Foster Creek, Sunrise and the Toledo Refinery. In late May, we responded to wildfire activity in northern Alberta by temporarily shutting-in production at Christina Lake to ensure the safety of our staff and assets. We resumed production in early June. Safety continues to be our top priority.
- **Acquisition of MEG Energy Corp.** On November 13, 2025, we completed the acquisition of MEG Energy Corp. ("MEG") through a plan of arrangement (the "MEG Acquisition"). Purchase consideration for the MEG Acquisition included $3.4 billion in cash partially funded through the receipt of a $2.7 billion term loan facility, and the issuance of 143.9 million Cenovus common shares with a fair value of $3.7 billion. The acquired MEG assets immediately contributed to our Christina Lake production and results.
- **Sale of interest in WRB Refining LP.** On September 30, 2025, we divested our entire 50 percent interest in the jointly-owned Wood River and Borger refineries held through WRB Refining LP ("WRB") (the "WRB Divestiture") for proceeds of US$1.3 billion (C$1.9 billion) after closing adjustments. The divestiture aligns with our strategy of owning and operating assets that are core to our business.
- **Record annual upstream production.** We achieved record annual upstream production averaging 834.2 thousand BOE per day (2024 – 797.2 thousand BOE per day), primarily due to record annual Oil Sands production averaging 644.1 thousand BOE per day (2024 – 610.7 thousand). Oil Sands production increased due to successful results from new well pads, additional production volumes following the MEG Acquisition and the completion of key growth projects.

- **Completed and advanced key Oil Sands growth projects.** We ramped-up production following the completion of the Narrows Lake tie-back to Christina Lake, and we completed the Foster Creek optimization project ahead of schedule. At Sunrise, we brought new well pads online to support continued production growth. At our Lloydminster conventional heavy oil assets, we made progress on our heavy oil development program.
- **Achieved Offshore milestones at the West White Rose Project.** The topsides were placed atop the concrete gravity structure, and we completed the subsea tie-ins to our existing production system at the *SeaRose* floating production, storage and offloading unit ("FPSO"). Hookup and commissioning of the platform continued to progress and was substantially completed in the fourth quarter of 2025, despite challenging offshore weather conditions.
- **Strong utilization in our downstream assets.** Average crude oil throughput ("throughput") in our downstream assets was 626.6 thousand barrels per day, representing a crude unit utilization of 95 percent, compared with 646.9 thousand barrels per day in 2024, representing crude unit utilization of 90 percent. Our Canadian assets achieved record annual throughput and continue to run at or above capacity, while the completion of turnarounds and operational improvement initiatives in our operated U.S. assets resulted in higher reliability.
- **Reported solid financial results.** Adjusted Funds Flow was $8.9 billion, an increase of $707 million from 2024, reflecting strong operating performance in our upstream and downstream operations, despite a weakened commodity price environment. Brent and WTI benchmark prices both decreased by 14 percent, partially offset by higher market crack spreads and the narrowing of the WTI-WCS differential. Cash from operating activities was $8.2 billion, a decrease from $9.2 billion in 2024, mainly due to changes in non-cash working capital.
- **Closed senior notes offerings.** In connection with the closing of the MEG Acquisition and upcoming debt maturities, the Company closed public offerings in Canada and the U.S. of $2.6 billion of senior unsecured notes. The proceeds of the offerings were used to fund the redemption of select senior unsecured notes and for general corporate purposes.
- **Completed the redemption of select senior notes.** The Company redeemed US$973 million in principal of senior unsecured notes due in 2027 and 2029, in full, including the US$600 million senior unsecured notes assumed with the MEG Acquisition. The Company also redeemed $750 million in principal of senior unsecured notes due in 2027, in full.
- **Delivered significant returns to shareholders.** We returned $3.8 billion to common and preferred shareholders, including the purchase of 89.4 million common shares for $2.0 billion through our normal course issuer bid ("NCIB"), $1.4 billion through common and preferred share base dividends, and the redemption of the Company's series 5 and series 7 preferred shares at a price of $25.00 per share for a total of $350 million. Following the MEG Acquisition, we have adjusted our shareholder returns framework to balance deleveraging with shareholder returns.
- **Raised our common share base dividend.** In the second quarter, the Board approved an 11 percent increase in the base dividend to $0.800 per common share annually. On February 18, 2026, the Board declared a first quarter dividend of $0.200 per common share.

Summary of Annual Results

($ millions, except where indicated)	**2025**	2024	2023
Upstream Production Volumes [1] [2] (MBOE/d)	**834.2**	797.2	778.7
Downstream Total Processed Inputs [3] [4] (Mbbls/d)	**667.5**	678.0	586.8
Crude Oil Unit Throughput [3] (Mbbls/d)	**626.6**	646.9	560.4
Downstream Production Volumes [3] (Mbbls/d)	**687.2**	693.1	599.2
Revenues	**49,696**	54,277	52,204
Operating Margin [5]	**10,608**	10,809	11,022
Operating Margin – Upstream [6]	**10,403**	11,121	9,870
Operating Margin – Downstream [6]	**205**	(312)	1,152
Cash From (Used In) Operating Activities	**8,228**	9,235	7,388
Adjusted Funds Flow [5]	**8,871**	8,164	8,803
Per Share – Basic [5] ($)	**4.90**	4.41	4.64
Per Share – Diluted [5] ($)	**4.87**	4.38	4.54
Capital Investment	**4,907**	5,015	4,298
Free Funds Flow [5]	**3,964**	3,149	4,505
Net Earnings (Loss)	**3,930**	3,142	4,109
Per Share – Basic ($)	**2.16**	1.68	2.15
Per Share – Diluted ($)	**2.15**	1.67	2.09
Total Assets	**63,424**	56,539	53,915
Total Long-Term Liabilities [5]	**25,472**	19,408	18,993
Long-Term Debt, Including Current Portion	**11,032**	7,534	7,108
Net Debt	**8,292**	4,614	5,060
Cash Returns to Common and Preferred Shareholders	**3,782**	3,246	2,798
Common Shares – Base Dividends	**1,423**	1,255	990
Base Dividends Per Common Share ($)	**0.780**	0.680	0.525
Common Shares – Variable Dividends	**—**	251	—
Variable Dividends Per Common Share ($)	**—**	0.135	—
Purchase of Common Shares Under NCIB	**1,995**	1,445	1,061
Payment for Purchase of Warrants	**—**	—	711
Dividends Paid on Preferred Shares	**14**	45	36
Preferred Share Redemption	**350**	250	—

(1) Refer to the Operating and Financial Results section of this MD&A for a summary of total upstream production by product type.
(2) Includes results of the MEG Acquisition from November 13, 2025.
(3) Represent Cenovus's net interest in refining operations. Following the WRB Divestiture, all refining operations are wholly-owned.
(4) Total processed inputs include crude oil and other feedstocks. Blending is excluded.
(5) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.
(6) Specified financial measure. See the Specified Financial Measures Advisory.

OPERATING AND FINANCIAL RESULTS

Selected Operating and Financial Results — Upstream

	2025	Percent Change	2024
Production Volumes by Segment [1] (MBOE/d)			
Oil Sands [2]	**644.1**	**5**	610.7
Conventional [3]	**122.8**	**2**	119.9
Offshore [4]	**67.3**	**1**	66.6
Total Production Volumes	**834.2**	**5**	797.2
Production Volumes by Product [1]			
Bitumen (Mbbls/d)	**616.8**	**4**	591.3
Heavy Crude Oil (Mbbls/d)	**25.1**	**43**	17.6
Light Crude Oil [5] (Mbbls/d)	**18.1**	**40**	12.9
NGLs (Mbbls/d)	**28.8**	**(10)**	32.0
Conventional Natural Gas (MMcf/d)	**872.4**	**1**	860.2
Total Production Volumes (MBOE/d)	**834.2**	**5**	797.2
Per-Unit Operating Expenses by Segment [6] ($/BOE)			
Oil Sands [2]	**11.81**	**4**	11.40
Conventional [3] [7]	**9.84**	**(18)**	11.99
Offshore [4] [7]	**16.88**	**(12)**	19.27
Oil and Gas Reserves [8] (MMBOE)			
Total Proved	**6,135**	**8**	5,664
Probable	**3,472**	**24**	2,793
Total Proved Plus Probable	**9,607**	**14**	8,457

(1) Refer to the Oil Sands, Conventional and Offshore reportable segments section of this MD&A for a summary of production by product type.
(2) For the year ended December 31, 2025, reported Oil Sands segment production and per-unit operating expenses includes results of the MEG Acquisition from November 13, 2025.
(3) For the year ended December 31, 2025, reported Conventional segment production and per-unit operating expenses include Cenovus's 30 percent equity interest in the Duvernay Energy Corporation ("Duvernay") joint venture, which is accounted for using the equity method in the Consolidated Financial Statements. Operating expenses for the Conventional segment, excluding our equity interests in the Duvernay joint venture, was $464 million.
(4) Reported Offshore segment production and per-unit operating expenses include Cenovus's 40 percent equity interest in the Husky-CNOOC Madura Limited ("HCML") joint venture, which is accounted for using the equity method in the Consolidated Financial Statements. Operating expenses for the Offshore segment, excluding our equity interests in the HCML joint venture, was $349 million (2024 – $423 million).
(5) Light crude oil corresponds to light crude oil and medium crude oil combined as defined by National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). Cenovus does not produce medium crude oil.
(6) Specified financial measure. See the Specified Financial Measures Advisory.
(7) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.
(8) Includes values attributable to Cenovus's 30 percent equity interest in the Duvernay joint venture and Cenovus's 40 percent equity interest in the HCML joint venture. See the Advisory – Interests in Joint Ventures section.

Production

Total upstream production increased in 2025, compared with 2024, due to:

- Incremental production at Christina Lake following the MEG Acquisition in November 2025 and the ramp-up of production from Narrows Lake.
- Successful results from new well pads at Foster Creek and the completion of the Foster Creek optimization project, which supported additional production.
- Production resuming at the White Rose field following the completion of the *SeaRose* asset life extension ("ALE") project.

The increase was partially offset by the temporary shut-in of production at our Rush Lake facilities in our Lloydminster thermal assets, due to a casing failure at a steam injection well that occurred in the second quarter of 2025. In the fourth quarter, we successfully restarted production and the phased ramp-up is progressing as expected.

Per-Unit Operating Expenses

For the year ended December 31, 2025, per-unit operating expenses increased in the Oil Sands segment compared with 2024, primarily due to higher fuel costs and higher costs at our Lloydminster thermal assets related to the incident at Rush Lake. Per-unit operating expenses decreased in the Conventional segment primarily due to lower turnaround costs, and processing and gathering costs compared with 2024. Per-unit operating expenses decreased in the Offshore segment compared with 2024, primarily due to higher sales volumes and lower repairs and maintenance expenses as the White Rose field resumed production following the completion of the *SeaRose* ALE project in the first quarter of 2025.

We continue to focus on controlling costs through securing long-term contracts, working with vendors and purchasing long-lead items to mitigate future cost escalations.

Selected Operating and Financial Results — Downstream

	2025	Percent Change	2024
Crude Oil Unit Throughput by Segment (Mbbls/d)			
Canadian Refining	**110.7**	**22**	90.5
U.S. Refining	**515.9**	**(7)**	556.4
Total Crude Oil Unit Throughput	**626.6**	**(3)**	646.9
Production Volumes by Product [1] (Mbbls/d)			
Gasoline	**266.7**	**(5)**	280.5
Distillates [2]	**210.5**	**(4)**	219.9
Synthetic Crude Oil	**52.0**	**27**	41.0
Asphalt	**41.8**	**(5)**	44.0
Ethanol	**5.0**	**4**	4.8
Other	**111.2**	**8**	102.9
Total Production Volumes	**687.2**	**(1)**	693.1
Per-Unit Operating Expenses by Segment [3] ($/bbl)			
Canadian Refining	**11.59**	**(49)**	22.56
U.S. Refining	**12.73**	**(2)**	12.99
Per-Unit Operating Expenses – Excluding Turnaround Costs by Segment [3] ($/bbl)			
Canadian Refining	**11.54**	**(25)**	15.38
U.S. Refining	**10.88**	**(6)**	11.55

(1) Refer to the Canadian Refining and U.S. Refining reportable segments section of this MD&A for a summary of production by product type.
(2) Includes diesel and jet fuel.
(3) Specified financial measure. See the Specified Financial Measures Advisory. In the Canadian Refining segment, operating expenses represent expenses associated with the Lloydminster Upgrader ("Upgrader"), the Lloydminster Refinery and the commercial fuels business.

Total downstream throughput and refined product production decreased in 2025. The decrease was primarily due to the WRB Divestiture and the impact of turnarounds completed at our Toledo Refinery and non-operated Wood River and Borger refineries during the year. The decrease in throughput and refined product production was partially offset by our Canadian Refining assets running at, or above, full capacity and ongoing operational improvement initiatives at our operated U.S. Refining assets.

In 2025, per-unit operating expenses excluding turnaround costs decreased in the Canadian Refining segment compared with 2024, due to lower project costs and higher total processed inputs. Total processed inputs were lower and operating expenses were higher in 2024, due to a major turnaround completed at the Upgrader in the second quarter of 2024.

In 2025, per-unit operating expenses excluding turnaround costs decreased in the U.S. Refining segment compared with 2024, primarily due to lower controllable operating expenses, partially offset by higher electricity costs.

Selected Consolidated Financial Results

Revenues

Revenues decreased eight percent compared with 2024, primarily due to a weakened commodity price environment combined with lower U.S. Refining sales volumes following the WRB Divestiture. The decrease was partially offset by higher sales volumes from our upstream assets and Canadian Refining segment.

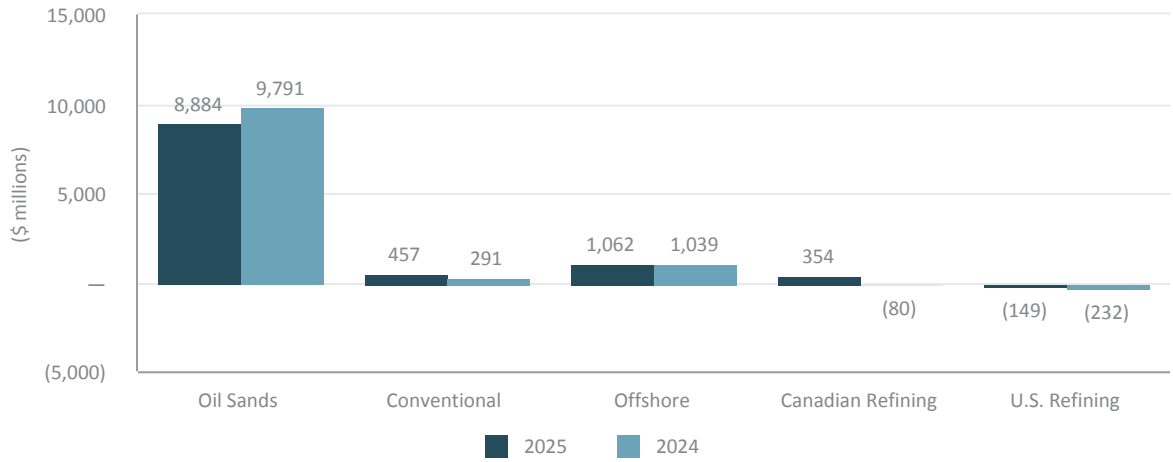
Operating Margin

Operating Margin is a non-GAAP financial measure and is used to provide a consistent measure of the cash-generating performance of our assets for comparability of our underlying financial performance between periods.

($ millions)	**2025**	2024
Gross Sales		
External Sales	**52,751**	57,726
Intersegment Sales	**8,941**	8,970
	61,692	66,696
Royalties	**(3,055)**	(3,449)
Revenues	**58,637**	63,247
Expenses		
Purchased Product	**30,078**	33,926
Transportation and Blending	**11,243**	11,331
Operating Expenses	**6,710**	7,159
Realized (Gain) Loss on Risk Management	**(2)**	22
Operating Margin	**10,608**	10,809

Operating Margin by Segment

Years Ended December 31, 2025 and 2024



Operating Margin decreased compared with 2024, primarily due to:

- Lower Realized Sales Prices impacting revenues in our Oil Sands segment due to lower benchmark WTI prices, partially offset by a narrower WTI-WCS differential.
- Increased operating expenses in our Oil Sands segment due to higher fuel costs and costs related to the incident at Rush Lake.

The decreases were partially offset by:

- The increase in Oil Sands production discussed above, which includes the accretive impact from the MEG Acquisition.
- Lower operating expenses and higher sales volumes in our Canadian Refining segment, as discussed above.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations.

($ millions)	**2025**	2024
Cash From (Used in) Operating Activities	**8,228**	9,235
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(280)**	(234)
Net Change in Non-Cash Working Capital	**(363)**	1,305
Adjusted Funds Flow	**8,871**	8,164

Adjusted Funds Flow was higher in 2025, compared with 2024, primarily due to lower current tax expense and lower cash-settled long-term incentive costs, partially offset by higher integration, transaction and other costs, and lower Operating Margin.

Cash from operating activities decreased in 2025, compared with 2024, primarily due to changes in non-cash working capital, partially offset by higher Adjusted Funds Flow, as discussed above. The net change in non-cash working capital was primarily due to an increase in accounts receivable, and decreases in accounts payable and income tax payable, partially offset by a decrease in inventories, excluding the impact of the MEG Acquisition and the WRB Divestiture.

Net Earnings (Loss)

Net earnings in 2025 was $3.9 billion (2024 – $3.1 billion). The increase was primarily due to unrealized foreign exchange gains in 2025 compared with losses in 2024, and lower income tax expense, partially offset by higher depreciation, depletion and amortization expense and lower Operating Margin.

Net Debt

As at December 31, ($ millions)	**2025**	2024
Short-Term Borrowings	**—**	173
Current Portion of Long-Term Debt	**—**	192
Long-Term Portion of Long-Term Debt	**11,032**	7,342
Total Debt	**11,032**	7,707
Cash and Cash Equivalents	**(2,740)**	(3,093)
Net Debt	**8,292**	4,614

Total Debt and Net Debt increased as at December 31, 2025, primarily due to the receipt of a $2.7 billion term loan facility and the issuance of $2.6 billion of senior unsecured notes. The increase was partially offset by the redemption and repayment of senior unsecured notes totaling $2.3 billion, which includes the US$600 million notes assumed in the MEG Acquisition, and unrealized foreign exchange gains due to the strengthening of the Canadian dollar. The increase in Net Debt was further offset by the receipt of proceeds from the WRB Divestiture.

Capital Investment [1]

($ millions)	2025	2024
Upstream		
Oil Sands	**2,944**	2,714
Conventional	**453**	421
Offshore	**934**	1,145
Total Upstream	**4,331**	4,280
Downstream		
Canadian Refining	**117**	208
U.S. Refining	**442**	488
Total Downstream	**559**	696
Corporate and Eliminations	**17**	39
Total Capital Investment	**4,907**	5,015

(1) Includes expenditures on property, plant and equipment ("PP&E"), exploration and evaluation ("E&E") assets, and capitalized interest. Excludes capital expenditures related to joint ventures accounted for using the equity method in the Consolidated Financial Statements.

Capital investment in 2025 was mainly related to:

- Sustaining, optimization and redevelopment programs in the Oil Sands segment, including the drilling of stratigraphic test wells as part of our integrated winter program.
- The progression of the West White Rose project.
- Growth projects in our Oil Sands segment, including the progression of the drilling program at our Lloydminster conventional heavy oil assets, the Sunrise growth program, the optimization project at Foster Creek and the Narrows Lake tie-back to Christina Lake.
- Reliability and sustaining activities in our refining segments.
- Drilling, completion, tie-in and infrastructure projects in the Conventional segment.

Drilling Activity

	Net Stratigraphic Test Wells and Observation Wells		Net Production Wells [1]	
	2025	2024	**2025**	2024
Foster Creek	**76**	85	**46**	22
Christina Lake [2]	**68**	61	**27**	23
Sunrise	**21**	40	**11**	14
Lloydminster Thermal	**68**	53	**12**	22
Lloydminster Conventional Heavy Oil	**2**	19	**83**	49
Other [3]	**—**	—	**5**	—
	235	258	**184**	130

(1) Steam-assisted gravity drainage ("SAGD") well pairs in the Oil Sands segment are counted as a single producing well.
(2) Includes results of the MEG Acquisition from November 13, 2025.
(3) Includes new resource plays.

Stratigraphic test wells were drilled to help identify future well pad locations and to further evaluate our assets. Observation wells were drilled to gather information and monitor reservoir conditions.

	2025			2024		
(net wells)	**Drilled**	**Completed**	**Tied-in**	Drilled	Completed	Tied-in
Conventional [1]	**53**	**54**	**54**	36	31	31

(1) Includes values attributable to Cenovus's 30 percent equity interest in the Duvernay joint venture.

In the Offshore segment, no wells were drilled or completed in 2025 (2024 – drilled and evaluated one exploration well in China).

COMMODITY PRICES UNDERLYING OUR FINANCIAL RESULTS

Key performance drivers for our financial results include commodity prices, quality and location price differentials, refined product prices and refining crack spreads, as well as the U.S./Canadian dollar and Chinese Yuan ("RMB")/Canadian dollar exchange rates. The following table shows selected market benchmark prices and average exchange rates to assist in understanding our financial results.

Selected Benchmark Prices and Exchange Rates [1]

				Year Ended December 31,		
(Average US$/bbl, unless otherwise indicated)	Q4 2025	Percent Change	Q4 2024	2025	Percent Change	2024
Dated Brent	**63.69**	**(15)**	74.69	**69.06**	**(14)**	80.76
WTI	**59.14**	**(16)**	70.27	**64.81**	**(14)**	75.72
Differential Dated Brent – WTI	**4.55**	**3**	4.42	**4.25**	**(16)**	5.04
WCS at Hardisty	**47.94**	**(17)**	57.71	**53.68**	**(12)**	60.97
Differential WTI – WCS at Hardisty	**11.20**	**(11)**	12.56	**11.13**	**(25)**	14.75
WCS at Hardisty (C$/bbl)	**66.89**	**(17)**	80.74	**75.07**	**(10)**	83.52
WCS at Nederland	**55.63**	**(15)**	65.69	**61.74**	**(11)**	69.69
Differential WTI – WCS at Nederland	**3.51**	**(23)**	4.58	**3.07**	**(49)**	6.03
Condensate (C5 at Edmonton)	**57.01**	**(19)**	70.66	**63.36**	**(13)**	72.94
Differential Condensate – WTI Premium/(Discount)	**(2.13)**	**(646)**	0.39	**(1.45)**	**(48)**	(2.78)
Differential Condensate – WCS at Hardisty Premium/(Discount)	**9.07**	**(30)**	12.95	**9.68**	**(19)**	11.97
Condensate (C$/bbl)	**79.54**	**(20)**	98.84	**83.63**	**(16)**	99.92
Synthetic at Edmonton	**57.84**	**(19)**	71.11	**64.47**	**(14)**	75.07
Differential Synthetic – WTI Premium/(Discount)	**(1.30)**	**(255)**	0.84	**(0.34)**	**(48)**	(0.65)
Synthetic at Edmonton (C$/bbl)	**80.69**	**(19)**	99.45	**90.15**	**(12)**	102.83
Refined Product Prices						
Chicago Regular Unleaded Gasoline ("RUL")	**70.66**	**(11)**	78.95	**80.81**	**(10)**	89.95
Chicago Ultra-low Sulphur Diesel ("ULSD")	**90.70**	**2**	89.28	**91.13**	**(7)**	97.47
Refining Benchmarks						
Chicago 3-2-1 Crack Spread [2]	**18.20**	**50**	12.12	**19.44**	**16**	16.74
Group 3 3-2-1 Crack Spread [2]	**19.25**	**52**	12.66	**20.63**	**23**	16.81
Renewable Identification Numbers ("RINs")	**6.04**	**50**	4.02	**5.81**	**55**	3.74
Upgrading Differential [3] (C$/bbl)	**13.53**	**(27)**	18.64	**14.92**	**(22)**	19.21
Natural Gas Prices						
AECO [4] (C$/Mcf)	**2.23**	**51**	1.48	**1.68**	**15**	1.46
NYMEX [5] (US$/Mcf)	**3.55**	**27**	2.79	**3.43**	**51**	2.27
Foreign Exchange Rates						
US$ per C$1 – Average	**0.717**	**—**	0.715	**0.716**	**(2)**	0.730
US$ per C$1 – End of Period	**0.730**	**5**	0.695	**0.730**	**5**	0.695
RMB per C$1 – Average	**5.084**	**(1)**	5.142	**5.144**	**(2)**	5.255

(1) These benchmark prices are not our Realized Sales Prices and represent approximate values. For our Realized Sales Prices refer to the Netback tables in the upstream reportable segments section of this MD&A.
(2) The average 3-2-1 crack spread is an indicator of the adjusted refining margin and is valued on a last-in, first-out accounting basis.
(3) The upgrading differential is the difference between synthetic crude oil at Edmonton and Lloydminster Blend crude oil at Hardisty. The upgrading differential does not precisely mirror the configuration and the product output of our Canadian Refining assets; however, it is used as a general market indicator.
(4) Alberta Energy Company ("AECO") 5A natural gas daily index.
(5) New York Mercantile Exchange ("NYMEX") natural gas monthly index.

Crude Oil and Condensate Benchmarks

In 2025, global crude oil benchmark prices, Brent and WTI, decreased compared with 2024, as global supply exceeded demand leading to inventory builds throughout the year. Global crude oil production increased considerably in 2025 as OPEC+ continued to unwind production cuts, while non-OPEC countries, including the United States, Canada and Brazil, also increased supply. Year-over-year demand growth in 2025 weakened compared with 2024 due to a combination of weaker macroeconomic conditions, trade tensions, and other softer industrial activity in major consuming regions.

WTI is an important benchmark for Canadian crude oil since it reflects inland North American crude oil prices, and the Canadian dollar equivalent is the basis for determining royalty rates for a number of our crude oil properties.

WCS is a blended heavy oil which consists of both conventional heavy oil and unconventional diluted bitumen. The WCS at Hardisty differential to WTI is a function of the quality differential of light and heavy crude, and the cost of transport. The WTI-WCS differential at Hardisty narrowed in 2025, compared with 2024, due to:

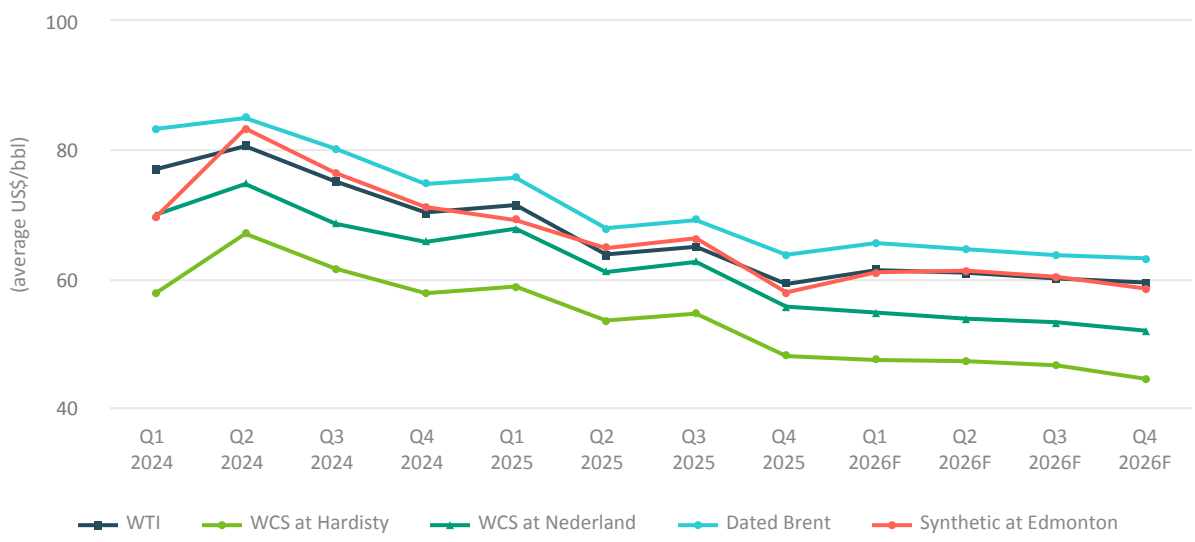
- The Trans Mountain Pipeline expansion project ("TMX") increasing market access for WCS crude.
- Low inventory levels in the Western Canadian Sedimentary Basin as well as strong global demand for heavy crudes.
- Strong pricing for fuel oil in which heavy grades yield more versus light grades.

WCS at Nederland is a heavy oil benchmark for sales of our product at the U.S. Gulf Coast ("USGC"). The WTI-WCS at Nederland differential is representative of the heavy oil quality differential and is influenced by global heavy oil refining capacity and global heavy oil supply. In 2025, the WTI-WCS at Nederland differential narrowed compared with 2024, due to strong global demand for heavy crudes, as well as other factors as mentioned above.

In Canada, we upgrade heavy crude oil and bitumen into a sweet synthetic crude oil, the Husky Synthetic Blend ("HSB"), at the Upgrader. The price realized for HSB is primarily driven by the price of WTI, and by the supply and demand of sweet synthetic crude oil from Western Canada, which influences the WTI-Synthetic differential.

In 2025, synthetic crude oil at Edmonton strengthened relative to WTI compared with 2024. The strength in pricing relative to 2024 was a function of deep discounts in the first quarter of 2024 due to high synthetic crude oil production in Alberta and the supply of light crude oil being above pipeline capacity on light crude oil pipelines with limited local storage capacity.

Crude Oil Benchmark Prices [(1)]



(1) Forward pricing as at February 2, 2026.

Blending condensate with bitumen enables our production to be transported through pipelines. Our blending ratios, calculated as diluent volumes as a percentage of total blended volumes, range from approximately 20 percent to 35 percent. The Condensate-WCS differential is an important benchmark, as a higher premium generally results in a decrease in Operating Margin when selling a barrel of blended crude oil. When the supply of condensate in Alberta does not meet the demand, Edmonton condensate prices may be driven by USGC condensate prices plus the cost to transport the condensate to Edmonton. Our blending costs are also impacted by the timing of purchases and deliveries of condensate into inventory to be available for use in blending, as well as timing of blended product sales.

In 2025, the average Edmonton condensate benchmark traded at a smaller discount to WTI compared with 2024, due to the same factors impacting the synthetic crude oil to WTI differential, as discussed above, as well as tight Canadian supply and low Canadian inventories.

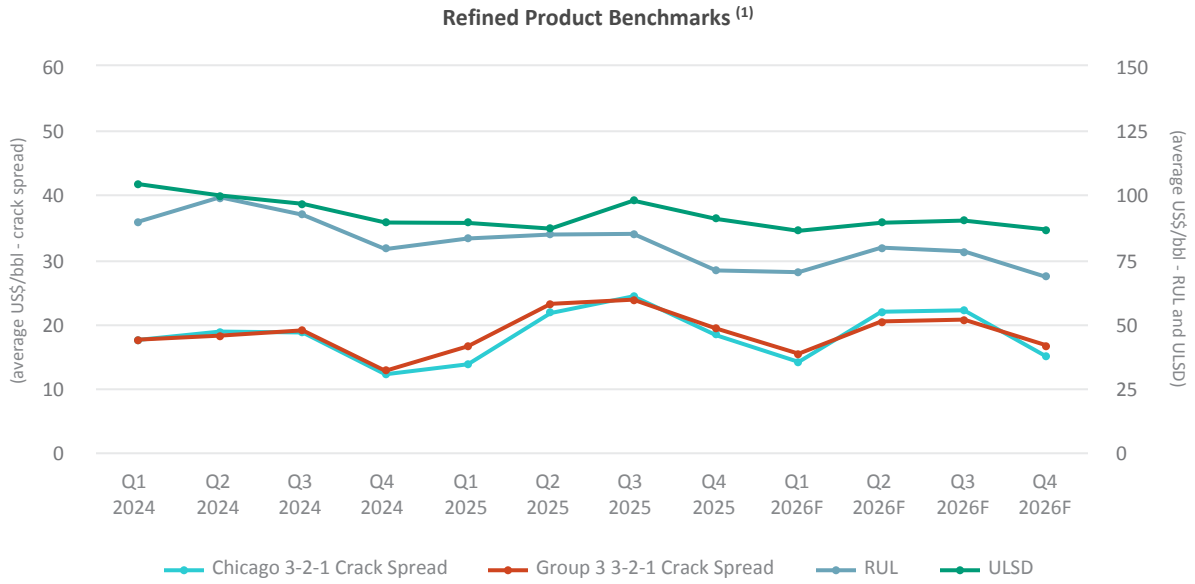
Refining Benchmarks

RUL and ULSD benchmark prices are representative of inland refined product prices and are used to derive the Chicago 3-2-1 market crack spread. The 3-2-1 market crack spread is an indicator of the adjusted refining margin generated by converting three barrels of crude oil into two barrels of regular unleaded gasoline and one barrel of ultra-low sulphur diesel, using current-month WTI-based crude oil feedstock prices and valued on a last-in, first-out basis.

In 2025, refined product crack spreads in Chicago and Group 3 increased compared with 2024. The increase can be largely attributed to strong product cracks as unplanned global and North American refinery outages supported refined product pricing and new refining capacity has been slow to ramp up. The average cost of RINs was higher in 2025, compared with 2024, due to weaker U.S. production and imports of renewable diesel and biodiesel causing a decline in RINs generation.

North American refining crack spreads are expressed on a WTI basis, while refined products are generally set by global prices. The strength of refining market crack spreads in the U.S. Midwest and Midcontinent generally reflects the differential between Brent and WTI benchmark prices.

Our adjusted refining margin is affected by various other factors such as the quality and purchase location of crude oil feedstock, refinery configuration and product output. The benchmark market crack spreads do not precisely mirror the configuration and product output of our refineries, or the location we sell product; however, they are used as a general market indicator.



(1) Forward pricing as at February 2, 2026.

Natural Gas Benchmarks

In 2025, AECO prices increased compared with 2024, though not as much as the increase in NYMEX pricing. NYMEX prices increased more than AECO as NYMEX prices were supported by strong liquified natural gas ("LNG") demand, while AECO prices were impacted by limited Western Canadian takeaway capacity, causing the AECO discount to NYMEX to widen. In 2025, both Western Canadian and U.S. natural gas production increased compared with 2024. The price received for our Asia Pacific natural gas production is largely based on long-term contracts.

Foreign Exchange Benchmarks

Our revenues are subject to foreign exchange exposure as the sales prices of our crude oil, NGLs, natural gas and refined products are determined by reference to U.S. dollar benchmark prices. An increase in the value of the Canadian dollar compared with the U.S. dollar has a negative impact on our reported revenue. In addition to our revenues being denominated in U.S. dollars, a significant portion of our long-term debt is also U.S. dollar denominated. As the Canadian dollar strengthens or weakens, our U.S. dollar debt gives rise to unrealized foreign exchange gains or losses, respectively, when translated to Canadian dollars. Changes in foreign exchange rates also impact the translation of our U.S. and Asia Pacific operations.

In 2025, on average, the Canadian dollar weakened relative to the U.S. dollar compared with 2024, positively impacting our reported revenues and negatively impacting our U.S. Refining operating expenses. A portion of our long-term sales contracts in the Asia Pacific region are priced in RMB. An increase in the value of the Canadian dollar relative to the RMB will decrease the revenues received in Canadian dollars from the sale of natural gas commodities in the region. In 2025, on average, the Canadian dollar weakened relative to RMB, compared with 2024, positively impacting our reported revenues.

Interest Rate Benchmarks

Our interest income, short-term and floating rate borrowing costs, reported decommissioning liabilities and fair value measurements are impacted by fluctuations in interest rates. A change in interest rates could change our net finance costs, affect how certain liabilities are measured, and impact our cash flow and financial results.

As at December 31, 2025, the Bank of Canada's policy interest rate was 2.25 percent. On January 28, 2026, the Bank of Canada held the policy interest rate at 2.25 percent.

OUTLOOK

Commodity Price Outlook

Global crude oil prices softened in 2025 as supply growth outpaced demand following the unwinding of OPEC+ voluntary cuts. Entering 2026, markets remain oversupplied, but price direction is uncertain and subject to volatility driven by policy decisions and geopolitical developments. OPEC+ policy continues to remain crucial to global oil supply and demand balances, and prices. Sanctions on Russian and Iranian crude and refined products have introduced persistent logistical challenges and altered trade flows globally. Policies regarding these regions will continue to be key factors that will drive energy supply. Policy and sanction uncertainty related to Venezuelan crude exports continues to influence global heavy crude oil supply and trade flows.

The global trade war and ongoing geopolitical tensions have the potential to reduce global GDP growth and oil demand, while increasing recessionary risks; however, the actual effects have been less pronounced than expected, and repeated pauses to tariffs have limited the direct economic impacts. There is potential for heightened price volatility across all commodities to continue until there is a firm resolution on the duration and magnitude of tariffs.

In addition to the above, our commodity pricing outlook for the next 12 months is influenced by the following:

- OPEC+ policy and the pace at which OPEC+ unwinds production cuts.
- In the near-term, there is a higher risk of a tariff-induced global economic slowdown that could slow oil demand.
- We expect the WTI-WCS at Hardisty differential will remain largely tied to global supply factors and heavy crude oil processing capacity, as long as supply does not exceed Canadian crude oil export capacity.
- Refined product prices and market crack spreads are likely to continue to fluctuate, adjusting for seasonal trends and refinery utilization in North America and globally.
- AECO and NYMEX natural gas prices are expected to remain volatile. The prospect of new LNG facilities in the U.S. and Canada coming into service or ramping up in the next year could increase demand and support North American natural gas prices. Weather will also continue to be a key driver of demand and impact prices.
- We expect the Canadian dollar to continue to be impacted by the pace at which the U.S. Federal Reserve Board and the Bank of Canada raise or lower benchmark lending rates relative to each other, the U.S. Administration's policies toward Canada-U.S. trade, crude oil prices and emerging macro-economic factors.

Most of our upstream crude oil and downstream refined product production is exposed to movements in the WTI crude oil price. Our integrated upstream and downstream operations help us to mitigate the impact of commodity price volatility. Crude oil production in our upstream assets is blended with condensate and butane and is used as crude oil feedstock at our downstream refining operations. Condensate extracted from our blended crude oil is sold back to our Oil Sands segment.

Our refining capacity is primarily focused in the U.S. Midwest, along with smaller exposures in the USGC and Alberta, exposing us to market crack spreads in these markets. We will continue to monitor market fundamentals and optimize run rates at our refineries accordingly.

Our exposure to crude oil differentials includes light-heavy and light-medium price differentials. The light-medium price differential exposure is focused on light-medium crudes in the U.S. Midwest market region where we have the majority of our refining capacity, and to a lesser degree, in the USGC and Alberta. Our exposure to light-heavy crude oil price differentials is composed of a global light-heavy component, a regional component in markets we transport barrels to, as well as the Alberta differentials, which could be subject to transportation constraints.

While we expect to see volatility in crude oil prices, we have the ability to partially mitigate the impact of crude oil and refined product differentials through the following:

- Transportation commitments and arrangements – using our existing firm service commitments for takeaway capacity and supporting transportation projects that move crude oil from our production areas to consuming markets, including tidewater markets.
- Integration – heavy oil refining capacity allows us to capture value from both the WTI-WCS differential for Canadian crude oil and spreads on refined products.
- Monitoring market fundamentals and optimizing run rates at our refineries accordingly.
- Traditional crude oil storage tanks in various geographic locations.

Key Priorities for 2026

Our 2026 priorities are focused on top-tier safety performance, integration of MEG, maintaining and growing our competitive advantages in our heavy oil value chain, advancing our major projects and progressing our sustainability initiatives, while continuing to focus on cost leadership and balancing shareholder returns with deleveraging.

Top-tier Safety Performance

Safe and reliable operations are our number one priority. We strive to ensure safe and reliable operations across our portfolio, and aim to be best-in-class operators for each of our major assets and businesses.

Integration of MEG

The MEG Acquisition is expected to further strengthen our oil sands assets by integrating top-tier adjacent assets at Christina Lake. In 2026, we plan to complete a fully integrated development plan for Christina Lake intended to increase production, reduce costs and capture synergies across the combined asset.

Heavy Oil Value Chain

Our heavy oil value chain includes all of our bitumen and heavy oil producing, midstream and pipeline-connected downstream assets. Across the value chain, we will focus on increasing our optionality, optimizing our working capital, improving our margins and reducing our break-even pricing.

Project Execution

Investing in future growth and profitability is a priority for us with several key projects underway, including the West White Rose project, the Amine Claus project at Foster Creek, the Christina Lake North expansion project, the Sunrise growth program and development of our Lloydminster assets.

Downstream Competitiveness

A competitive, reliable downstream business is essential to our integrated business. It allows us to be agile in our response to fluctuating demand for refined products and serves as a natural partial hedge to heavy oil differentials.

We will continue to implement operational improvements to our downstream assets to maximize the long-term profitability of our assets.

Returns to Shareholders

Maintaining a strong balance sheet with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle is a key element of Cenovus's capital allocation framework. Upon closing of the MEG Acquisition, we adjusted our shareholder returns framework to balance deleveraging with shareholder returns. Our long-term Net Debt target of $4.0 billion remains unchanged and the adjusted framework allows us to make progress towards this target. For further details, see the Liquidity and Capital Resources section of this MD&A.

Cost Leadership

We aim to maximize shareholder value through a continued focus on low-cost structures and margin optimization across our business. We are focused on reducing operating, capital, and general and administrative costs, realizing the full value of our integrated strategy, while making decisions that support long-term value for Cenovus.

Sustainability

Sustainability is central to Cenovus's culture. We have established goals in our sustainability focus areas and we continue to advance work to support progress against these commitments.

The Government of Canada and the Government of Alberta have announced a framework aimed at strengthening federal-provincial collaboration in the energy sector to support a number of overlapping goals, including Canada's greenhouse gas ("GHG") emissions reduction ambitions. We continue to support our commitment to the Pathways Alliance, including efforts to reach agreements with the federal and provincial governments that provide sufficient fiscal and regulatory support to progress large-scale carbon capture projects, while maintaining global competitiveness.

Cenovus's updated social commitments and 2024 Corporate Social Responsibility report, highlighting our performance in safety, Indigenous reconciliation, and acceptance and belonging, are available on our website at cenovus.com.

2026 Corporate Guidance

Our 2026 corporate guidance dated December 10, 2025, is available on our website at cenovus.com.

Our 2026 corporate guidance for total capital investment is between $5.0 billion and $5.3 billion. This includes $3.5 billion to $3.6 billion directed towards sustaining capital to maintain base production and support continued safe and reliable operations, and between $1.2 billion and $1.4 billion of investment directed towards growth projects, such as:

- The Christina Lake North expansion project.
- The drilling program and ramping-up of production at the West White Rose field.
- The Sunrise growth program and the development of our Lloydminster assets.

The following table is a sub-set of our full updated guidance for 2026:

	Capital Investment ($ millions)	**Production** (MBOE/d)	**Crude Oil Unit Throughput** (Mbbls/d)
Upstream			
Oil Sands	**3,500 - 3,600**	**755 - 780**	
Conventional	**450 - 500**	**120 - 125**	
Offshore	**450 - 500**	**70 - 80**	
Upstream Total	**4,400 - 4,600**	**945 - 985**	
Downstream			
Canadian Refining			**105 - 110**
U.S. Refining			**325 - 340**
Downstream Total	**600 - 700**		**430 - 450**
Corporate and Eliminations	**Up to 25**		

REPORTABLE SEGMENTS

Our Operations

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Sunrise, Lloydminster thermal and Lloydminster conventional heavy oil assets, as well as Christina Lake, which includes the results of the MEG Acquisition completed in November 2025. Cenovus jointly owns and operates pipeline gathering systems and terminals through the equity-accounted investment in Husky Midstream Limited Partnership ("HMLP"). The sale and transportation of Cenovus's production and third-party commodity trading volumes are managed and marketed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Conventional,** includes assets rich in NGLs and natural gas in Alberta and British Columbia in the Edson, Clearwater and Rainbow Lake operating areas, in addition to the Northern Corridor, which includes Elmworth and Wapiti. The segment also includes interests in numerous natural gas processing facilities. Cenovus's NGLs and natural gas production is marketed and transported, with additional third-party commodity trading volumes, through access to capacity on third-party pipelines, export terminals and storage facilities. These provide flexibility for market access to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Offshore,** includes offshore operations, exploration and development activities in the east coast of Canada and the Asia Pacific region, representing China and the equity-accounted investment in HCML, which is engaged in the exploration for, and production of, NGLs and natural gas in offshore Indonesia.

Downstream Segments

- **Canadian Refining,** includes the owned and operated Lloydminster upgrading and asphalt refining complex, which converts heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus also owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. The Company's commercial fuels business across Canada is included in this segment. Cenovus markets its production and third-party commodity trading volumes in an effort to use its integrated network of assets to maximize value.
- **U.S. Refining,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima, Superior and Toledo refineries. On September 30, 2025, Cenovus divested its entire 50 percent interest in the jointly-owned Wood River and Borger refineries held through WRB with operator Phillips 66. The U.S. Refining segment included the WRB results up to the date of divestiture. Cenovus markets its own and third-party refined products.

Corporate and Eliminations

Corporate and Eliminations, includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate-related derivative instruments and foreign exchange. Eliminations include adjustments for feedstock and internal usage of crude oil, natural gas, condensate, other NGLs and refined products between segments; transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal; the sale of condensate extracted from blended crude oil production in the Canadian Refining segment and sold to the Oil Sands segment; and unrealized profits in inventory. Eliminations are recorded based on market prices.

UPSTREAM

Oil Sands

In 2025, we:

- Delivered safe and reliable operations, including the safe execution of turnarounds at Foster Creek and Sunrise.
- Completed the MEG Acquisition, which immediately contributed to our Christina Lake results.
- Produced 644.1 thousand BOE per day (2024 – 610.7 thousand BOE per day).
- Generated Operating Margin of $8.9 billion (2024 – $9.8 billion).
- Averaged a Netback of $38.37 per barrel (2024 – $44.88 per barrel).
- Invested capital of $2.9 billion for sustaining activities and growth projects.

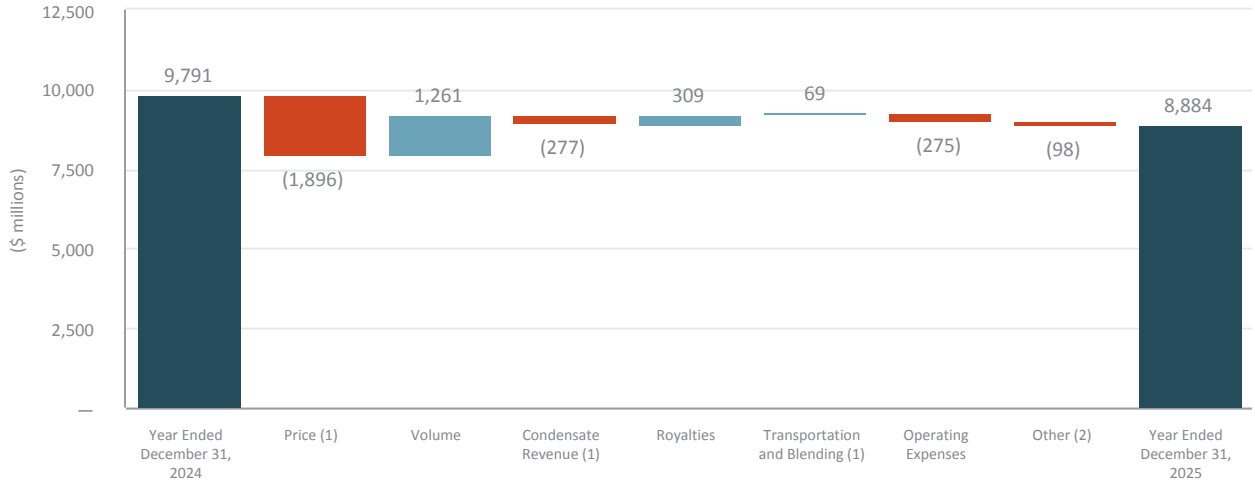
In 2025, we completed the Narrows Lake tie-back to Christina Lake and ramped-up production. All major process units at the Foster Creek optimization project were brought online and the project was completed ahead of schedule, supporting incremental production. At Sunrise, we brought new well pads online to support continued production growth. At our Lloydminster conventional heavy oil assets, we made progress on our heavy oil development program.

Financial Results

($ millions)	**2025**	2024
Gross Sales		
External Sales	**21,541**	21,857
Intersegment Sales	**6,786**	6,590
	28,327	28,447
Royalties	**(2,920)**	(3,274)
Revenues	**25,407**	25,173
Expenses		
Purchased Product	**2,886**	1,851
Transportation and Blending	**10,875**	11,000
Operating	**2,754**	2,511
Realized (Gain) Loss on Risk Management	**8**	20
Operating Margin	**8,884**	9,791
Unrealized (Gain) Loss on Risk Management	**3**	(16)
Depreciation, Depletion and Amortization	**3,433**	3,117
Exploration Expense	**11**	2
(Income) Loss from Equity-Accounted Affiliates	**(38)**	(14)
Segment Income (Loss)	**5,475**	6,702

Operating Margin Variance

Year Ended December 31, 2025



(1) Reported revenues include the value of condensate sold as heavy oil blend. Condensate costs are recorded in transportation and blending expenses. The crude oil price excludes the impact of condensate purchases. Changes to price include the impact of realized risk management gains and losses.

(2) Includes third-party sourced volumes, construction and other activities not attributable to the production of crude oil or natural gas.

Operating Results

	2025	2024
Total Sales Volumes [1] (MBOE/d)	**644.7**	599.5
Crude Oil Production by Asset (Mbbls/d)		
Foster Creek	**206.1**	196.0
Christina Lake [2]	**254.3**	234.2
Sunrise	**53.8**	49.6
Lloydminster Thermal	**102.6**	111.5
Lloydminster Conventional Heavy Oil	**25.1**	17.6
Total Crude Oil Production [3] (Mbbls/d)	**641.9**	608.9
Natural Gas [1] (MMcf/d)	**13.8**	11.1
Total Production (MBOE/d)	**644.1**	610.7
Netback [4] ($/bbl)		
Realized Sales Price	**72.07**	80.20
Royalties	**12.61**	14.92
Transportation and Blending	**9.28**	9.00
Operating	**11.81**	11.40
Total Netback ($/bbl)	**38.37**	44.88

(1) Bitumen, heavy crude oil and natural gas. Natural gas is a conventional natural gas product type.

(2) Includes results of the MEG Acquisition from November 13, 2025.

(3) Crude oil production is primarily bitumen, except for Lloydminster conventional heavy oil, which is heavy crude oil.

(4) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.

Revenues

Gross sales were relatively consistent in 2025 compared with 2024, due to lower Realized Sales Prices, offset by higher sales volumes.

Price

Our bitumen and heavy oil production must be blended with condensate to reduce its viscosity in order to transport it to market through pipelines. Within our Netback calculations, our realized bitumen and heavy oil sales price excludes the impact of purchased condensate; however, it is influenced by the price of condensate. As the cost of condensate used for blending increases relative to the price of blended crude oil or our blend ratio increases, our realized bitumen and heavy oil sales price decreases.

Our Realized Sales Price decreased in 2025 compared with 2024, mainly due to a lower WTI benchmark price, partially offset by a narrower WTI-WCS differential.

Cenovus makes storage and transportation decisions to use our marketing and transportation infrastructure, including storage and pipeline assets, in order to optimize product mix, delivery points, transportation commitments and customer diversification. To price protect our inventories associated with storage or transport decisions, Cenovus may employ various price alignment and volatility management strategies, including risk management contracts, to reduce volatility in future cash flows and improve cash flow stability.

In 2025, approximately 37 percent (2024 – 33 percent) of our sales volumes were sold at destinations outside of Alberta and approximately 25 percent (2024 – 20 percent) of our sales volumes were sold to our downstream operations.

Production Volumes

Oil Sands crude oil production increased in 2025, compared with 2024, primarily due to:

- Incremental production at Christina Lake following the MEG Acquisition in November 2025 and the ramp-up of production from Narrows Lake.
- Successful results from new well pads at Foster Creek and the completion of the Foster Creek optimization project, which supported additional production.
- Strong base production and additional volumes from new development wells at our Lloydminster conventional heavy oil assets.

The increase was partially offset by the temporary shut-in of production at our Rush Lake facilities following an incident in the second quarter of 2025.

Royalties

Royalty calculations for our Oil Sands segment are based on government prescribed royalty regimes in Alberta and Saskatchewan.

In Alberta, oil sands royalties are based on government prescribed pre- and post-payout royalty rates, which are determined on a sliding scale using the Canadian dollar equivalent WTI benchmark price.

Royalties for a pre-payout project are based on a monthly calculation that applies a royalty rate (ranging from one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price) to the gross revenues from the project. Sunrise is a pre-payout project.

Royalties for a post-payout project are based on an annualized calculation which uses the greater of: (1) the gross revenues multiplied by the applicable royalty rate (one percent to nine percent, based on the Canadian dollar equivalent WTI benchmark price); or (2) the net revenues of the project multiplied by the applicable royalty rate (25 percent to 40 percent, based on the Canadian dollar equivalent WTI benchmark price). Gross revenues are a function of sales revenues less diluent costs and transportation costs. Net revenues are calculated as sales revenues less diluent costs, transportation costs, and allowed operating and capital costs.

In Saskatchewan, royalty calculations are based on an annual rate that is applied to each project, which includes each project's Crown and freehold split. For Crown royalties, the pre-payout calculation is based on one percent of product revenues and the post-payout calculation is based on 20 percent of operating margin. The freehold calculation is limited to post-payout projects and is based on an eight percent rate.

Effective Royalty Rate [1]

Percent	**2025**	2024
Foster Creek	**22.5**	24.0
Christina Lake	**25.3**	27.3
Sunrise	**6.2**	6.1
Lloydminster [2]	**12.2**	11.7
Total Effective Royalty Rate	**20.0**	21.0

(1) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(2) Composed of Lloydminster thermal and Lloydminster conventional heavy oil assets.

In 2025, Oil Sands royalties decreased compared with 2024, mainly due to lower realized pricing, partially offset by higher sales volumes. The Oil Sands effective royalty rate decreased, primarily due to lower realized prices and lower Alberta sliding scale oil sands royalty rates, combined with annual adjustments in 2025.

Expenses

Transportation and Blending

In 2025, blending expenses decreased compared with 2024, primarily due to lower condensate prices, partially offset by higher sales volumes.

In 2025, transportation expenses and per-unit transportation expenses increased compared with 2024, primarily due to higher sales volumes on TMX and increased pipeline transportation rates on shipments to U.S. destinations, partially offset by lower sales volumes at U.S. destinations.

Per-Unit Transportation Expenses [1]

($/bbl)	**2025**	2024
Foster Creek	**14.36**	13.57
Christina Lake	**6.86**	6.53
Sunrise	**15.42**	16.07
Lloydminster [2]	**3.23**	3.95
Total Oil Sands	**9.28**	9.00

(1) Specified financial measure. See the Specified Financial Measures Advisory.
(2) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.

At Foster Creek, per-unit transportation expenses increased primarily due to higher sales volumes sold at West Coast destinations through the use of TMX, increasing to 32 percent (2024 – 20 percent), partially offset by lower rail costs. In 2025, our sales volumes to U.S. destinations were relatively consistent at 36 percent, compared with 37 percent in 2024.

At Christina Lake, per-unit transportation expenses increased primarily due to higher pipeline rates and higher sales volumes at West Coast destinations through the use of TMX, which increased to one percent, compared with no sales volumes in 2024. In 2025, our sales volumes to U.S. destinations were relatively consistent at 17 percent, compared with 18 percent in 2024.

At Sunrise, per-unit transportation expenses decreased primarily due to lower sales volumes at U.S. destinations, partially offset by higher use of TMX. In 2025, 36 percent of our sales volumes were sold at U.S. destinations (2024 – 67 percent) and 51 percent of our sales volumes were sold at West Coast destinations (2024 – 18 percent).

At Lloydminster, per-unit transportation expenses decreased primarily due to sales volumes at U.S. destinations decreasing to one percent compared with three percent in 2024.

Operating

Primary drivers of our operating expenses in 2025 were fuel, repairs and maintenance, and workforce. Total operating expenses in 2025 increased compared with 2024, primarily due to higher fuel costs and higher costs at our Lloydminster thermal assets related to the incident at Rush Lake.

Per-Unit Operating Expenses [1]

($/bbl)	2025	Percent Change	2024
Foster Creek			
Fuel	**2.12**	**1**	2.10
Non-Fuel	**7.64**	**(2)**	7.77
Total	**9.76**	**(1)**	9.87
Christina Lake			
Fuel	**2.23**	**7**	2.09
Non-Fuel	**5.98**	**(9)**	6.54
Total	**8.21**	**(5)**	8.63
Sunrise			
Fuel	**3.68**	**27**	2.89
Non-Fuel	**13.85**	**21**	11.47
Total	**17.53**	**22**	14.36
Lloydminster [2]			
Fuel	**2.98**	**9**	2.74
Non-Fuel	**17.03**	**15**	14.78
Total	**20.01**	**14**	17.52
Total Oil Sands			
Fuel	**2.46**	**7**	2.30
Non-Fuel	**9.35**	**3**	9.10
Total	**11.81**	**4**	11.40

(1) Specified financial measure. See the Specified Financial Measures Advisory.
(2) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.

Per-unit fuel expenses increased in 2025, compared with 2024, due to higher AECO benchmark pricing and increased consumption volumes from well pads coming online at our Sunrise assets.

Foster Creek per-unit non-fuel costs decreased slightly in 2025, compared with 2024, primarily due to higher sales volumes, partially offset by higher turnaround costs in the second quarter of 2025.

Christina Lake per-unit non-fuel costs decreased in 2025, primarily due to higher sales volumes and lower turnaround expenses, compared with 2024.

Sunrise per-unit non-fuel costs increased in 2025, compared with 2024, primarily due to turnaround activities in the second and third quarters of 2025, partially offset by higher sales volumes.

Lloydminster per-unit non-fuel costs increased in 2025, compared with 2024, due to higher costs related to the Rush Lake incident in the second quarter of 2025.

Conventional

In 2025, we:

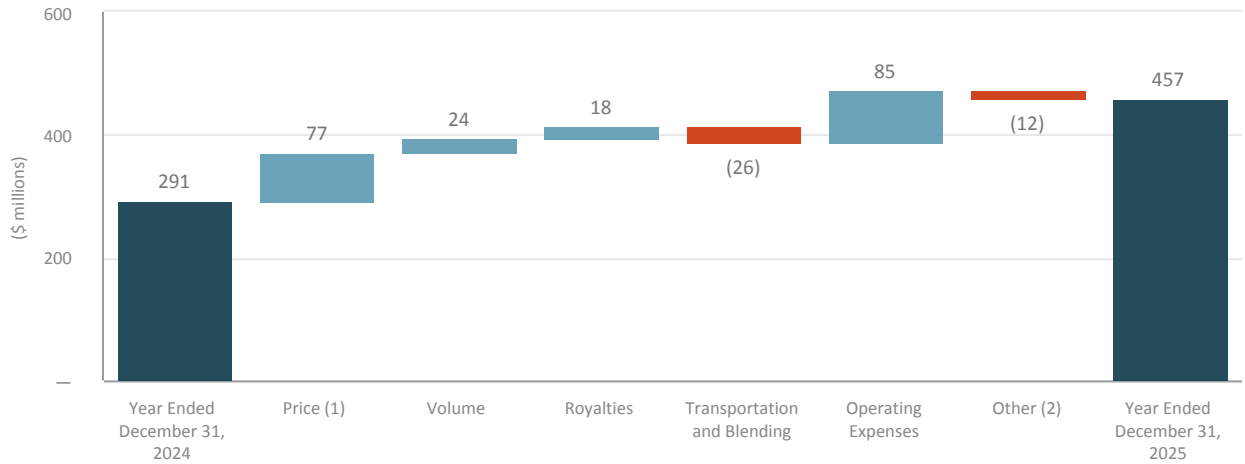
- Delivered safe and reliable operations.
- Produced 122.8 thousand BOE per day (2024 – 119.9 thousand BOE per day).
- Generated Operating Margin of $457 million, an increase of $166 million from 2024.
- Earned a Netback of $10.37 per BOE (2024 – $6.48 per BOE).
- Invested capital of $453 million, primarily related to drilling, completion, tie-in and infrastructure projects.

Financial Results

($ millions)	2025	2024
Gross Sales		
External Sales	**1,305**	1,211
Intersegment Sales	**1,355**	1,848
	2,660	3,059
Royalties	**(55)**	(76)
Revenues	**2,605**	2,983
Expenses		
Purchased Product	**1,337**	1,823
Transportation and Blending	**351**	320
Operating	**464**	555
Realized (Gain) Loss on Risk Management	**(4)**	(6)
Operating Margin	**457**	291
Unrealized (Gain) Loss on Risk Management	**(4)**	4
Depreciation, Depletion and Amortization	**479**	442
Exploration Expense	**22**	1
(Income) Loss From Equity-Accounted Affiliates	**—**	2
Segment Income (Loss)	**(40)**	(158)

Operating Margin Variance

Year Ended December 31, 2025



(1) Changes to price include the impact of realized risk management gains and losses.
(2) Includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.

Operating Results

	2025	2024
Total Sales Volumes [1] (MBOE/d)	**122.8**	119.9
Realized Sales Price [1] [2] ($/BOE)		
Light Crude Oil ($/bbl)	**78.50**	92.68
NGLs ($/bbl)	**51.83**	54.62
Conventional Natural Gas ($/Mcf)	**3.13**	2.51
Production by Product [1]		
Light Crude Oil (Mbbls/d)	**5.0**	4.9
NGLs (Mbbls/d)	**21.2**	21.0
Conventional Natural Gas (MMcf/d)	**579.3**	563.8
Total Production (MBOE/d)	**122.8**	119.9
Conventional Natural Gas Production (percentage of total)	**79**	78
Crude Oil and NGLs Production (percentage of total)	**21**	22
Effective Royalty Rate [1] [3] (percent)	**8.0**	10.3
Netback [1] [2] ($/BOE)		
Realized Sales Price	**26.95**	25.18
Royalties	**1.30**	1.73
Transportation and Blending	**5.44**	4.98
Operating	**9.84**	11.99
Total Netback ($/BOE)	**10.37**	6.48

(1) For the year ended December 31, 2025, reported production volumes, sales volumes, associated per-unit values and effective royalty rates include Cenovus's 30 percent equity interest in the Duvernay joint venture.
(2) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.
(3) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.

Revenues

Gross sales decreased in 2025, compared with 2024, due to lower commodity trading volumes sourced from third parties, partially offset by higher Realized Sales Prices and sales volumes.

Price

Our total Realized Sales Price increased in 2025, compared with 2024, primarily due to higher sales volumes to U.S. destinations. In 2025, 31 percent of our natural gas sales volumes were sold at U.S. destinations (2024 – 28 percent) where NYMEX natural gas benchmark prices increased to US$3.43 per Mcf (2024 – US$2.27 per Mcf). The year-over-year increase was also due to AECO natural gas benchmark prices increasing to $1.68 per Mcf (2024 – $1.46 per Mcf).

Production Volumes

Production volumes increased in 2025, compared with 2024, primarily due to strong base performance. In 2024, production volumes were lower due to turnaround activities.

Royalties

The Conventional assets are subject to royalty regimes in Alberta and British Columbia. Royalties and the effective royalty rate decreased in 2025, compared with 2024, primarily due to overall lower benchmark prices used to calculate our royalties.

Expenses

Transportation

Our transportation expenses reflect charges for the movement of crude oil, NGLs and natural gas from the point of production to where the product is sold. In 2025, transportation expenses and per-unit transportation expenses increased compared with 2024, due to increased pipeline transportation rates.

Operating

Primary drivers of operating expenses in 2025 were repairs and maintenance, workforce and property tax costs. Total operating expenses and per-unit operating expenses decreased compared with 2024, primarily due to lower turnaround costs, and processing and gathering costs.

Offshore

In 2025, we:

- Delivered safe and reliable operations.
- Produced 67.3 thousand BOE per day of light crude oil, NGLs and natural gas (2024 – 66.6 thousand BOE per day).
- Generated Operating Margin of $1.1 billion, an increase of $23 million from 2024.
- Averaged a Netback of $52.27 per BOE (2024 – $52.38 per BOE).
- Invested capital of $934 million, mainly related to the progression of the West White Rose project.

In 2025, we have made significant progress on the West White Rose project. The topsides were placed atop the concrete gravity structure, and we completed the subsea tie-ins to our existing production system at the *SeaRose* FPSO. Hookup and commissioning of the platform continued to progress and was substantially completed in the fourth quarter of 2025, despite challenging offshore weather conditions. First oil is anticipated in the second quarter of 2026.

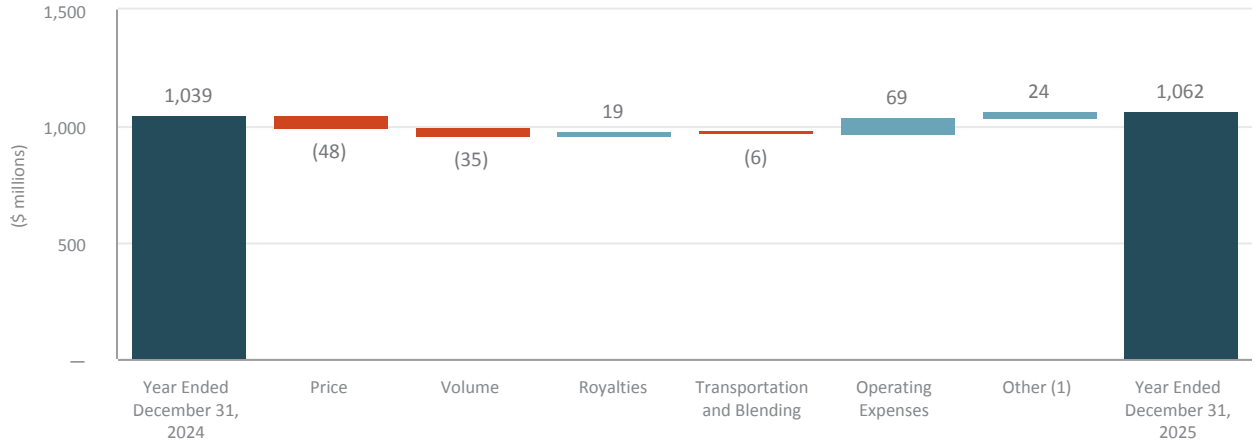
Financial Results

	2025			2024		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore**	Atlantic	Asia Pacific	Offshore
Gross Sales						
External Sales	**420**	**1,088**	**1,508**	322	1,250	1,572
Intersegment Sales	**—**	**—**	**—**	—	—	—
	420	**1,088**	**1,508**	322	1,250	1,572
Royalties	**(4)**	**(76)**	**(80)**	(2)	(97)	(99)
Revenues	**416**	**1,012**	**1,428**	320	1,153	1,473
Expenses						
Purchased Product	**—**	**—**	**—**	—	—	—
Transportation and Blending	**17**	**—**	**17**	11	—	11
Operating	**226**	**123**	**349**	290	133	423
Operating Margin [(1)]	**173**	**889**	**1,062**	19	1,020	1,039
Depreciation, Depletion and Amortization			**440**			563
Exploration Expense			**8**			66
(Income) Loss from Equity-Accounted Affiliates			**(31)**			(53)
Segment Income (Loss)			**645**			463

(1) Atlantic and Asia Pacific Operating Margin are non-GAAP financial measures. See the Specified Financial Measures Advisory.

Operating Margin Variance

Year Ended December 31, 2025



(1) Includes other activities not attributable to the production of crude oil and natural gas.

Operating Results

	2025	2024
Sales Volumes		
Atlantic (Mbbls/d)	**11.3**	8.0
Asia Pacific (MBOE/d)		
China	**38.3**	42.6
Indonesia [1]	**15.9**	16.0
Total Asia Pacific	**54.2**	58.6
Total Sales Volumes (MBOE/d)	**65.5**	66.6
Production by Product		
Atlantic – Light Crude Oil (Mbbls/d)	**13.1**	8.0
Asia Pacific [1]		
NGLs (Mbbls/d)	**7.6**	11.0
Conventional Natural Gas (MMcf/d)	**279.3**	285.3
Total Asia Pacific (MBOE/d)	**54.2**	58.6
Total Production (MBOE/d)	**67.3**	66.6
Effective Royalty Rate [2] (percent)		
Atlantic	**1.0**	0.7
Asia Pacific [1]	**11.1**	9.5

(1) Reported sales volumes, production volumes and royalty rates reflect Cenovus's 40 percent equity interest in the HCML joint venture.
(2) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.

Netbacks [1]

($/BOE, except where indicated)	**Atlantic** ($/bbl)	**2025** China	**Indonesia**	**Total Offshore** [2]
Realized Sales Price	**97.11**	**77.81**	**59.31**	**76.66**
Royalties	**0.95**	**5.43**	**14.34**	**6.81**
Transportation and Blending	**4.04**	**—**	**—**	**0.70**
Operating Expenses	**54.07**	**8.16**	**11.39**	**16.88**
Netback	**38.05**	**64.22**	**33.58**	**52.27**

($/BOE, except where indicated)	Atlantic ($/bbl)	2024 China	Indonesia	Total Offshore [2]
Realized Sales Price	109.58	80.26	57.82	78.40
Royalties	0.72	6.19	9.32	6.29
Transportation and Blending	3.81	—	—	0.46
Operating Expenses	97.70	7.61	10.93	19.27
Netback	7.35	66.46	37.57	52.38

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.
(2) Reported per-unit values reflect Cenovus's 40 percent equity interest in the HCML joint venture.

Revenues

Gross sales decreased in 2025, compared with 2024, due to lower sales volumes in China and lower Realized Sales Prices, partially offset by higher sales volumes in our Atlantic operations.

Price

Our Atlantic Realized Sales Price decreased in 2025, compared with 2024, due to lower Brent benchmark pricing. The prices we receive for natural gas sold in Asia Pacific are set under long-term contracts.

Production Volumes

Light crude oil production from the White Rose and Terra Nova fields are offloaded from the *SeaRose* and *Terra Nova* FPSO vessels, respectively, to tankers and stored at an onshore terminal before shipment to buyers, which results in a timing difference between production and sales.

Atlantic production increased in 2025, compared with 2024, primarily due to production resuming at the White Rose field in the first quarter of 2025 following completion of the *SeaRose* ALE project. Atlantic production was lower in 2024, as production at the White Rose field was suspended in late December 2023 in preparation for the project.

Asia Pacific production decreased in 2025, compared with 2024, primarily due to lower contracted sales volumes in China.

Royalties

Royalty rates at the White Rose and Terra Nova fields are governed by an agreement with the Government of Newfoundland and Labrador which limits royalties to one percent of gross revenues until certain costs incurred have been recovered. For the year ended December 31, 2025, the Atlantic effective royalty rate was relatively consistent compared with 2024.

Royalty rates in Asia Pacific are governed by production-sharing contracts, in which production is shared with the Chinese and Indonesian governments.

Expenses

Transportation

Transportation expenses include the costs of transporting crude oil from the *SeaRose* and *Terra Nova* FPSOs to onshore terminals and storage costs. Transportation expenses for the year ended December 31, 2025, increased to $17 million (2024 – $11 million), primarily due to higher Atlantic sales volumes.

Operating

Primary drivers of our Atlantic operating expenses in 2025 were repairs and maintenance, costs related to vessels and air services, and workforce. Operating expenses decreased compared with 2024, primarily due to lower repairs and maintenance, and vessels and air service costs as the *SeaRose* ALE project was completed in the first quarter of 2025. Per-unit operating expenses decreased compared with 2024, due to higher sales volumes and lower costs related to the *SeaRose* ALE project, as discussed.

Primary drivers of our China operating expenses in 2025 were repairs and maintenance, workforce and insurance costs. Per-unit operating expenses increased in 2025, compared with 2024, primarily due to lower sales volumes.

Primary drivers of our Indonesia operating expenses in 2025 were repairs and maintenance, and workforce costs. Per-unit operating expenses increased, compared with 2024, due to higher repairs and maintenance costs, partially offset by lower vessel costs.

DOWNSTREAM

Canadian Refining

In 2025, we:

- Delivered safe and reliable operations.
- Achieved record annual throughput of 110.7 thousand barrels per day and crude unit utilization of 103 percent (2024 – 90.5 thousand barrels per day and 84 percent, respectively).
- Incurred per-unit operating expenses excluding turnaround costs of $11.54 per barrel (2024 – $15.38 per barrel).
- Generated Operating Margin of $354 million, an increase of $434 million from 2024.
- Invested capital of $117 million, primarily focused on sustaining activities.

Financial and Operating Results

($ millions)	**2025**	2024
Revenues	**5,079**	5,310
Purchased Product	**4,128**	4,483
Gross Margin [(1)]	**951**	827
Expenses		
Operating	**597**	907
Operating Margin	**354**	(80)
Depreciation, Depletion and Amortization	**178**	185
Segment Income (Loss)	**176**	(265)

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory.

($ millions, except where indicated)	**2025**	2024
Gross Margin	**951**	827
Add (Deduct):		
Inventory Holding (Gain) Loss [(1)]	**3**	(2)
Adjusted Gross Margin [(2)]	**954**	825
Adjusted Refining Margin [(3)] ($/bbl)	**19.57**	20.72

(1) Inventory holding (gain) loss reflects the difference between the cost of volumes produced at current-period costs and the cost of volumes produced under the first-in, first-out ("FIFO") or weighted average cost basis, as required by IFRS Accounting Standards.
(2) Non-GAAP financial measure. See the Specified Financial Measures Advisory.
(3) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory. Revenues from the Upgrader, the Lloydminster Refinery and the commercial fuels business for the year ended December 31, 2025, were $4.8 billion (2024 – $5.0 billion).

Revenues, Adjusted Gross Margin and Adjusted Refining Margin

The Upgrader processes blended heavy crude oil and bitumen into high-value synthetic crude oil and low-sulphur diesel. Upgrading Gross Margin is primarily dependent on the differential between the sales price of synthetic crude oil and diesel, and the cost of heavy crude oil and bitumen feedstock.

The Lloydminster Refinery processes blended heavy crude oil into asphalt, bulk distillates and industrial products. Gross Margin is largely dependent on asphalt and industrial products pricing, and the cost of heavy crude oil feedstock.

Revenues decreased compared with 2024, due to lower refined product pricing partially offset by higher sales volumes.

Adjusted Gross Margin increased in 2025, compared with 2024, primarily due to lower feedstock costs as a result of lower benchmark crude pricing and higher sales volumes, partially offset by lower refined product pricing and the narrowing of the WTI-WCS differential.

Adjusted Refining Margin decreased in 2025, as the increase in Adjusted Gross Margin, as discussed above, was more than offset by the increase in total processed inputs.

(Mbbls/d, except where indicated)	2025	2024
Operable Capacity	**108.0**	108.0
Total Processed Inputs	**119.4**	96.6
Crude Oil Unit Throughput	**110.7**	90.5
Crude Unit Utilization (percent)	**103**	84
Total Production	**127.3**	103.1
Synthetic Crude Oil	**52.0**	41.0
Asphalt	**17.9**	15.7
Diesel	**15.2**	10.8
Other	**37.2**	30.8
Ethanol	**5.0**	4.8

The Upgrader and Lloydminster Refinery source their crude oil feedstock from our Oil Sands segment. In 2025, 14 percent of our Oil Sands segment's sales volumes were purchased by our Canadian Refining segment (2024 – 12 percent).

Throughput and total production increased in 2025, compared with 2024. In 2025, our assets ran at, or above, full capacity due to ongoing improvement initiatives and high asset reliability. In 2024, we safely completed the largest turnaround in the history of the Upgrader, which decreased throughput and increased operating expenses.

Operating Expenses

The following table and discussion represent operating expenses associated with the Upgrader, the Lloydminster Refinery and the commercial fuels business.

($ millions, except where indicated)	2025	2024
Operating Expenses – Upgrading and Refining	**505**	798
Operating Expenses – Excluding Turnaround Costs	**503**	544
Operating Expenses – Turnaround Costs	**2**	254
Per-Unit Operating Expenses [(1)] ($/bbl)	**11.59**	22.56
Per-Unit Operating Expenses – Excluding Turnaround Costs	**11.54**	15.38
Per-Unit Operating Expenses – Turnaround Costs	**0.05**	7.18

(1) Specified financial measure. See the Specified Financial Measures Advisory.

Primary drivers of operating expenses were workforce, and repairs and maintenance.

In 2025, operating expenses decreased compared with 2024, mainly due to lower turnaround costs and other project costs. Turnaround costs and other project costs were higher in 2024 due to the turnaround completed at the Upgrader, as discussed above.

Operating expenses excluding turnaround costs decreased in 2025, compared with 2024, due to lower project costs.

In 2025, the decrease in operating expenses, combined with increased total processed inputs, resulted in decreased per-unit operating expense metrics compared with 2024.

U.S. Refining

In 2025, we:

- Delivered safe and reliable operations.
- Recorded throughput of 515.9 thousand barrels per day compared with 556.4 thousand barrels per day in 2024 and crude unit utilization of 94 percent (2024 – 91 percent).
- Decreased per-unit operating expenses excluding turnaround costs to $10.88 per barrel (2024 – $11.55 per barrel).
- Recorded an Operating Margin shortfall of $149 million (2024 – $232 million).
- Invested capital of $442 million, primarily focused on reliability and sustaining activities.
- Completed the WRB Divestiture on September 30, 2025.

Financial and Operating Results

($ millions)	2025	2024
Revenues	**24,118**	28,308
Purchased Product	**21,727**	25,769
Gross Margin [1]	**2,391**	2,539
Expenses		
Operating	**2,546**	2,763
Realized (Gain) Loss on Risk Management	**(6)**	8
Operating Margin	**(149)**	(232)
Unrealized (Gain) Loss on Risk Management	**(5)**	8
Depreciation, Depletion and Amortization	**566**	462
Segment Income (Loss)	**(710)**	(702)

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory.

($ millions, except where indicated)	2025	2024
Gross Margin	**2,391**	2,539
Add (Deduct):		
Inventory Holding (Gain) Loss [1]	**298**	(23)
Adjusted Gross Margin [2]	**2,689**	2,516
Adjusted Refining Margin [2] ($/bbl)	**13.44**	11.83
Weighted Average Crack Spread, Net of RINs (US$/bbl)	**13.85**	13.01
Weighted Average Crack Spread, Net of RINs (C$/bbl)	**19.34**	17.82
Adjusted Market Capture [2] (percent)	**69**	67

(1) Inventory holding (gain) loss reflects the difference between the cost of volumes produced at current-period costs and the cost of volumes produced under the FIFO or weighted average cost basis, as required by IFRS Accounting Standards.
(2) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.

Revenues

Revenues decreased in 2025, compared with 2024, primarily due to lower sales volumes as a result of the WRB Divestiture and lower refined product pricing.

Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture

Benchmark market crack spreads do not precisely mirror the refinery configuration for crude diet and product yields, or the location we sell product; however, they are used as a general market indicator.

In 2025, the Chicago 3-2-1 crack spread increased 16 percent and the Group 3 3-2-1 crack spread increased 23 percent compared with 2024. The increase in crack spreads was partially offset by a 55 percent increase in the average cost of RINs, compared with 2024.

Year-over-year, Adjusted Gross Margin increased primarily due to improved reliability, the receipt of Small Refinery Exemption waivers, and a pipeline settlement. The increase in weighted average crack spreads, net of RINs, was offset by the narrowing of the WTI-WCS differential.

Adjusted Refining Margin, which is the Adjusted Gross Margin on a per-barrel basis, is affected by many factors. Some of these factors include the type of crude oil feedstock processed; refinery configuration and the proportion of gasoline, distillates and secondary product output; and the cost of feedstock.

Adjusted Refining Margin and Adjusted Market Capture increased in 2025, compared with 2024, due to the increase in Adjusted Gross Margin discussed above and lower total processed inputs.

(Mbbls/d, except where indicated)	**2025**	2024
Operable Capacity [1]	**549.9**	612.3
Total Processed Inputs	**548.1**	581.4
Crude Oil Unit Throughput	**515.9**	556.4
Heavy Crude Oil	**197.9**	219.6
Light/Medium Crude Oil	**318.0**	336.8
Crude Unit Utilization [1] (percent)	**94**	91
Total Refined Product Production	**559.9**	590.0
Gasoline	**266.7**	280.5
Distillates [2]	**195.3**	209.1
Asphalt	**23.9**	28.3
Other	**74.0**	72.1

(1) For the year ended December 31, 2025, reported operable capacity and crude unit utilization reflects the weighted average impact of the WRB Divestiture, which closed on September 30, 2025.
(2) Includes diesel and jet fuel.

Throughput and refined product production decreased in 2025, compared with 2024. The decrease was primarily due to the WRB Divestiture on September 30, 2025, and turnarounds at our Toledo Refinery and non-operated Wood River and Borger refineries during the year. For the nine months ended September 30, 2025, WRB recorded crude oil throughput of 238.7 thousand barrels per day and refined product production of 248.8 thousand barrels per day net to Cenovus. The decreased throughput and refined product production was partially offset by improved reliability across our operated refineries, driven by ongoing operational improvements made to the U.S. Refining business. In 2024, throughput and refined product production were affected by the turnarounds at the Lima Refinery and non-operated Borger Refinery.

Operating Expenses

($ millions, except where indicated)	**2025**	2024
Operating Expenses	**2,546**	2,763
Operating Expenses – Excluding Turnaround Costs	**2,176**	2,457
Operating Expenses – Turnaround Costs	**370**	306
Per-Unit Operating Expenses [1] ($/bbl)	**12.73**	12.99
Per-Unit Operating Expenses – Excluding Turnaround Costs	**10.88**	11.55
Per-Unit Operating Expenses – Turnaround Costs	**1.85**	1.44

(1) Specified financial measure. See the Specified Financial Measures Advisory.

Primary drivers of operating expenses were repairs and maintenance, workforce and turnaround costs.

Operating expenses decreased in 2025, compared with 2024, primarily due to lower repairs and maintenance, and project costs, partially offset by an increase in turnaround costs. Overall operating expenses were lower in 2025, compared with 2024, due in part to the WRB Divestiture in September 2025.

Turnaround costs increased compared with 2024, due to the turnaround completed at the Toledo Refinery and at the non-operated Wood River and Borger refineries. In 2024, turnarounds were completed at the Lima Refinery and the non-operated Borger refinery.

Operating expenses excluding turnaround costs and related per-unit metrics for 2025 decreased compared with 2024. This was mainly due to lower controllable operating expenses, including lower repairs and maintenance and project costs, as well as the positive benefits of ongoing business improvement initiatives and improved reliability in our operated downstream assets. The decreases in operating expenses excluding turnaround costs were partially offset by higher electricity costs.

CORPORATE AND ELIMINATIONS

Financial Results

($ millions)	2025	2024
Realized (Gain) Loss on Risk Management	**(20)**	24
Unrealized (Gain) Loss on Risk Management	**(9)**	16
General and Administrative	**812**	794
Finance Costs, Net	**569**	514
Integration, Transaction and Other Costs	**234**	166
Foreign Exchange (Gain) Loss, Net	**(361)**	462
(Gain) Loss on Divestiture of Assets	**(87)**	(119)
Other (Income) Loss, Net	**(115)**	(55)

General and Administrative

Primary drivers of our general and administrative expenses in 2025 were workforce and information technology related costs. The increase in general and administrative costs was primarily due to higher long-term incentive costs, partially offset by general cost saving initiatives.

Finance Costs, Net

Net finance costs were higher in 2025, compared with 2024, primarily due to lower interest income, and higher interest expenses on higher average debt. Refer to the Liquidity and Capital Resources section of this MD&A for further details on long-term debt.

The annualized weighted average interest rate on outstanding debt for 2025 was 4.5 percent (2024 – 4.5 percent).

Integration, Transaction and Other Costs

In 2025, we incurred $234 million in integration, transaction and other costs largely due to integration and transaction costs from the MEG Acquisition and costs related to the standardization of data governance to enhance efficiency and effectiveness of the Company's information technology systems.

In 2024, we incurred costs of $166 million, primarily related to modernizing and replacing certain information technology systems, optimizing business processes and standardizing data across the Company.

Foreign Exchange (Gain) Loss, Net

($ millions)	2025	2024
Unrealized Foreign Exchange (Gain) Loss	**(424)**	550
Realized Foreign Exchange (Gain) Loss	**63**	(88)
	(361)	462

Unrealized foreign exchange losses and gains were primarily due to the translation of U.S. denominated debt. As at December 31, 2025, the Canadian dollar strengthened five percent relative to the U.S. dollar at December 31, 2024. As at December 31, 2024, the Canadian dollar was eight percent weaker relative to the U.S. dollar at December 31, 2023. In 2025, realized foreign exchange losses were primarily related to working capital and the repayment of U.S. denominated debt.

(Gain) Loss on Divestiture of Assets

In 2025, the Company recorded a before-tax gain of $119 million related to the WRB Divestiture. The Company also divested certain Lloydminster thermal assets in the Oil Sands segment and recorded a before-tax loss of $58 million.

Prior to the closing of the MEG Acquisition, the Company held an aggregate of 25.0 million common shares of MEG. The acquisition-date fair value of the previously held MEG common shares was estimated to be $775 million and the net carrying value was $752 million. Cenovus recognized a revaluation gain of $23 million, which is recorded in gain (loss) on divestiture of assets in net earnings (loss).

In 2024, we recorded a before-tax gain of $65 million on the divestiture of assets related to Duvernay, and a before-tax gain of $51 million for the sale of non-core assets in our Conventional segment.

Income Taxes

($ millions)	**2025**	2024
Current Tax		
Canada	**540**	1,141
United States	**(1)**	9
Asia Pacific	**198**	214
Other International	**41**	39
Total Current Tax Expense (Recovery)	**778**	1,403
Deferred Tax Expense (Recovery)	**(231)**	(474)
	547	929

For the year ended December 31, 2025, the decline in current income tax expense was primarily due to the impact of the MEG Acquisition. The effective tax rate for 2025 was 12.2 percent (2024 – 22.8 percent). The lower effective tax rate in 2025 is primarily attributable to the reclassification of the cumulative foreign currency translation adjustment associated with the WRB Divestiture, which is not tax effected.

Our effective tax rate is a function of the relationship between total tax expense (recovery) and the amount of earnings (loss) before income taxes. The effective tax rate differs from the statutory tax rate for many reasons, including but not limited to, different tax rates between jurisdictions, non-taxable foreign exchange (gains) losses, adjustments for changes in tax rates and other legislation.

Tax interpretations, regulations and legislation in the various jurisdictions in which Cenovus and its subsidiaries operate are subject to change. We believe that our provision for income taxes is adequate. There are usually a number of tax matters under review, and with consideration of the current economic environment, income taxes are subject to measurement uncertainty. The timing of the recognition of income and deductions for the purpose of current tax expense is determined by relevant tax legislation.

QUARTERLY RESULTS

Our results for the fourth quarter of 2025 reflect strong operational performance in the upstream business, lower throughput in our downstream operations, mainly due to the impact of the WRB Divestiture, and financial results impacted by a declining commodity price environment compared with the third quarter of 2025.

- Upstream production averaged 917.9 thousand BOE per day, an increase of 85.0 thousand BOE per day from the third quarter of 2025, mainly due to completion of the MEG Acquisition in November 2025. In addition, production increased due to successful development and optimization programs at our Lloydminster thermal assets.
- In the quarter, we achieved milestones for key projects. We fully ramped-up production at the Narrows Lake tie-back to Christina Lake project. All major process units at the Foster Creek optimization project were brought online and the project was completed ahead of schedule, supporting incremental production. At Sunrise, the first of the new well pads in the east development area commenced steam injection.
- Commissioning of the platform at the West White Rose project continued despite challenging weather conditions. Construction and welding is complete and integration testing is underway.
- Downstream throughput decreased 35 percent from the third quarter of 2025 to 465.5 thousand barrels per day, due to the WRB Divestiture.
- Benchmark WTI prices decreased from US$64.93 per barrel to US$59.14 per barrel, and WCS at Hardisty decreased from US$54.54 per barrel to US$47.94 per barrel in the fourth quarter of 2025. Additionally, the Chicago 3-2-1 crack spread and the Group 3 3-2-1 crack spread fell 25 percent and 19 percent, respectively, from the third quarter of 2025 to US$18.20 and US$19.25 per barrel, respectively.
- U.S. Refining Adjusted Market Capture increased 41 percent from the third quarter to 106 percent, driven by the receipt of a pipeline settlement in the quarter and continued reliability, which allowed us to take advantage of market conditions.
- Cash from operating activities increased to $2.4 billion from $2.1 billion in the third quarter of 2025, and Adjusted Funds Flow increased to $2.7 billion, an eight percent increase from the third quarter, as the lower Operating Margin was more than offset by lower current tax expense.
- We returned $1.1 billion to shareholders through common and preferred share base dividends of $380 million, and $714 million through our NCIB.

Summary of Quarterly Results

($ millions, except where indicated)	2025 Q4	2025 Q3	2025 Q2	2025 Q1	2024 Q4	2024 Q3	2024 Q2	2024 Q1
Average Commodity Prices [1] (US$/bbl)								
Dated Brent	**63.69**	69.07	67.82	75.66	74.69	80.18	84.94	83.24
WTI	**59.14**	64.93	63.74	71.42	70.27	75.09	80.57	76.96
WCS at Hardisty	**47.94**	54.54	53.47	58.75	57.71	61.54	66.96	57.65
Differential WTI-WCS at Hardisty	**11.20**	10.39	10.27	12.67	12.56	13.55	13.61	19.31
Chicago 3-2-1 Crack Spread [2]	**18.20**	24.24	21.64	13.68	12.12	18.62	18.76	17.45
Group 3 3-2-1 Crack Spread [2]	**19.25**	23.72	23.07	16.48	12.66	18.95	18.13	17.50
RINs	**6.04**	6.33	6.12	4.76	4.02	3.89	3.39	3.68
Upstream Production Volumes [3]								
Bitumen (Mbbls/d)	**696.2**	615.2	552.1	602.5	608.6	569.6	591.7	595.4
Heavy Crude Oil (Mbbls/d)	**28.1**	25.4	25.0	21.8	18.0	16.3	18.1	17.9
Light Crude Oil (Mbbls/d)	**22.3**	16.3	17.0	16.8	12.3	13.6	13.5	12.5
NGLs (Mbbls/d)	**27.9**	27.8	29.9	29.8	31.7	31.0	33.0	32.4
Conventional Natural Gas (MMcf/d)	**860.4**	889.5	851.4	887.9	873.3	844.6	867.2	855.8
Total Production Volumes (MBOE/d)	**917.9**	832.9	765.9	818.9	816.0	771.3	800.8	800.9
Downstream Total Processed Inputs [4] (Mbbls/d)	**498.4**	757.6	714.9	700.5	700.5	674.4	652.9	683.8
Crude Oil Unit Throughput [4] (Mbbls/d)	**465.5**	710.7	665.8	665.4	666.7	642.9	622.7	655.2
Downstream Production Volumes [4] (Mbbls/d)	**527.5**	770.3	729.4	722.4	722.6	685.2	659.5	702.1
Revenues	**10,883**	13,195	12,319	13,299	12,813	13,819	14,582	13,063
Operating Margin [5]	**2,777**	2,954	2,066	2,811	2,274	2,408	2,936	3,191
Operating Margin – Upstream [6]	**2,628**	2,590	2,137	3,048	2,670	2,731	3,089	2,631
Operating Margin – Downstream [6]	**149**	364	(71)	(237)	(396)	(323)	(153)	560
Cash From (Used in) Operating Activities	**2,408**	2,131	2,374	1,315	2,029	2,474	2,807	1,925
Adjusted Funds Flow [5]	**2,674**	2,466	1,519	2,212	1,601	1,960	2,361	2,242
Per Share – Basic [5] ($)	**1.47**	1.38	0.84	1.21	0.88	1.06	1.27	1.20
Per Share – Diluted [5] ($)	**1.46**	1.38	0.84	1.21	0.87	1.05	1.26	1.19
Capital Investment	**1,360**	1,154	1,164	1,229	1,478	1,346	1,155	1,036
Free Funds Flow [5]	**1,314**	1,312	355	983	123	614	1,206	1,206
Excess Free Funds Flow [5]	**(1,597)**	745	(306)	373	(416)	146	735	832
Net Earnings (Loss)	**934**	1,286	851	859	146	820	1,000	1,176
Per Share – Basic ($)	**0.51**	0.72	0.47	0.47	0.08	0.44	0.53	0.62
Per Share – Diluted ($)	**0.50**	0.72	0.45	0.47	0.07	0.42	0.53	0.62
Total Assets	**63,424**	53,573	55,820	56,380	56,539	54,680	56,000	54,994
Long-Term Debt, Including Current Portion	**11,032**	7,156	7,241	7,524	7,534	7,199	7,275	7,227
Net Debt	**8,292**	5,255	4,934	5,079	4,614	4,196	4,258	4,827
Cash Returns to Common and Preferred Shareholders	**1,094**	1,274	819	595	706	1,070	1,034	436
Common Shares – Base Dividends	**376**	356	364	327	330	329	334	262
Base Dividends Per Common Share ($)	**0.200**	0.200	0.200	0.180	0.180	0.180	0.180	0.140
Common Shares – Variable Dividends	**—**	—	—	—	—	—	251	—
Variable Dividends Per Common Share ($)	**—**	—	—	—	—	—	0.135	—
Purchase of Common Shares Under NCIB	**714**	918	301	62	108	732	440	165
Dividends Paid on Preferred Shares	**4**	—	4	6	18	9	9	9
Preferred Share Redemption	**—**	—	150	200	250	—	—	—

(1) These benchmark prices are not our Realized Sales Prices and represent approximate values.
(2) The average 3-2-1 crack spread is an indicator of the refining margin and is valued on a last-in, first-out accounting basis.
(3) Includes results of the MEG Acquisition from November 13, 2025.
(4) Represent Cenovus's net interest in refining operations. Following the WRB Divestiture, all refining operations are wholly-owned.
(5) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory.
(6) Specified financial measure. See the Specified Financial Measures Advisory.

Fourth Quarter 2025 Results Compared with the Fourth Quarter 2024

The summary below compares financial and operating results for the three months ended December 31, 2025, compared with the same period in 2024.

Upstream Production Volumes

Total upstream production increased 101.9 thousand BOE per day in the fourth quarter of 2025, compared with 2024, primarily due to:

- Incremental production at Christina Lake following the MEG Acquisition in November 2025 and the ramp-up of production from Narrows Lake.
- Successful results from new well pads at Foster Creek and the completion of the Foster Creek optimization project, which supported additional production.
- Production resuming at the White Rose field following the completion of the *SeaRose* ALE project.

The increases were partially offset by the temporary shut-in of production at our Rush Lake facilities following an incident in the second quarter of 2025. In the fourth quarter, we successfully restarted production and the phased ramp-up is progressing as expected.

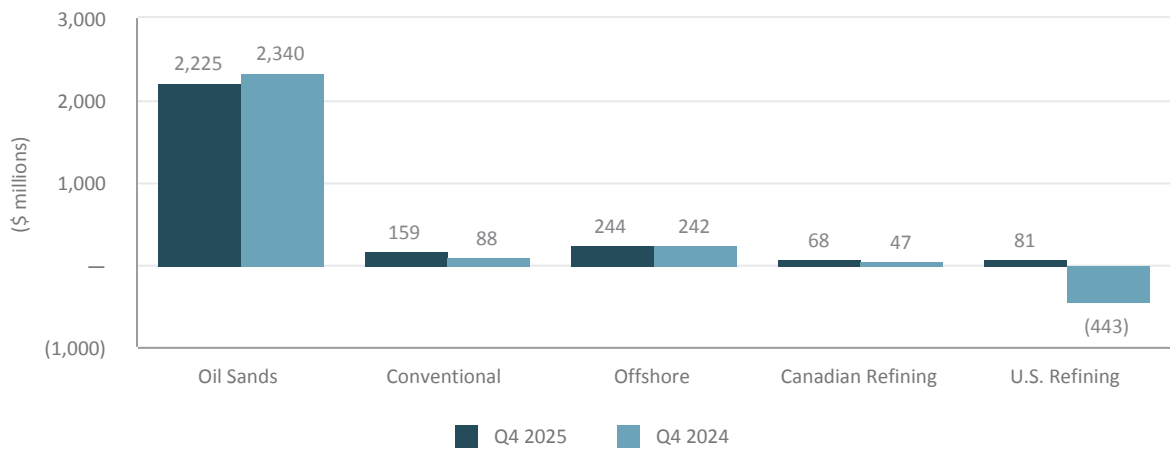
Downstream Refining Throughput and Production

Canadian Refining operations were strong in the fourth quarter with crude unit utilization of 105 percent (2024 – 97 percent). Throughput increased 8.5 thousand barrels per day to 112.9 thousand barrels per day and production increased 12.9 thousand barrels per day to 131.3 thousand barrels per day compared with 2024. In 2025, our assets ran at, or above full capacity due to ongoing improvement initiatives and continued high asset reliability.

U.S. Refining crude unit utilization increased to 97 percent (2024 – 92 percent) due to higher reliability and ongoing operational improvements. Throughput decreased 209.7 thousand barrels per day to 352.6 thousand barrels per day and total refined product production decreased 208.0 thousand barrels per day to 396.2 thousand barrels per day compared with 2024, primarily due to the WRB Divestiture.

Operating Margin

Three Months Ended December 31, 2025 and 2024



Operating Margin increased compared with the fourth quarter of 2024, primarily due to:

- Higher sales volumes in our Oil Sands and Canadian Refining segments.
- Higher market crack spreads in our U.S. Refining segment and the receipt of a pipeline settlement during the quarter.

The increase was partially offset by:

- Lower Realized Sales Prices impacting revenues in our Oil Sands segment due to lower benchmark WTI prices, partially offset by a narrower WTI-WCS differential.
- Increased operating expenses in our Oil Sands segment due to higher fuel costs.

Cash From (Used in) Operating Activities and Adjusted Funds Flow

Cash from operating activities increased $379 million to $2.4 billion in the fourth quarter of 2025, compared with the fourth quarter of 2024, primarily due to lower current tax expense and higher Operating Margin, partially offset by the changes in non-cash working capital. The 2025 net change in non-cash working capital was primarily due to decreases in accounts receivable. In 2024, the net change in non-cash working capital was primarily due to increases in accounts payable and taxes payable, combined with a decrease in accounts receivable, partially offset by increased inventories.

Adjusted Funds Flow increased to $2.7 billion in the fourth quarter of 2025, compared with $1.6 billion in 2024, primarily due to lower current tax expense and higher Operating Margin, partially offset by integration, transaction and other costs related to the MEG Acquisition.

Net Earnings (Loss)

Net earnings were $934 million in the fourth quarter of 2025 compared with $146 million in the fourth quarter of 2024. The increase was primarily due to an increase in Operating Margin and foreign exchange gains, compared with losses in 2024, partially offset by an increase in depreciation, depletion and amortization.

Capital Investment

Capital investment was $1.4 billion in the fourth quarter of 2025, compared with $1.5 billion in the fourth quarter of 2024, as we continued our sustaining activities and upstream growth projects.

OIL AND GAS RESERVES

As at December 31, 2025 (before royalties) (1) (2)	Bitumen (3) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (4) (Bcf)	Total (MMBOE)
Total Proved	5,697	87	59	1,745	**6,135**
Probable	3,227	71	28	878	**3,472**
Total Proved Plus Probable	8,924	158	87	2,622	**9,607**

As at December 31, 2024 (before royalties) (1) (2)	Bitumen (3) (MMbbls)	Light and Medium Oil (MMbbls)	NGLs (MMbbls)	Conventional Natural Gas (4) (Bcf)	Total (MMBOE)
Total Proved	5,179	91	69	1,950	**5,664**
Probable	2,500	77	37	1,071	**2,793**
Total Proved Plus Probable	7,679	168	107	3,021	**8,457**

(1) Totals may not sum due to rounding.
(2) Includes values attributable to Cenovus's 30 percent equity interest in the Duvernay joint venture and 40 percent equity interest in the HCML joint venture.
(3) Includes heavy crude oil that is not material.
(4) Includes shale gas that is not material.

The following developments occurred in 2025 compared with 2024:

- Bitumen gross total proved and gross total proved plus probable reserves increased by 518 million barrels and 1,245 million barrels, respectively. The changes were due to the MEG Acquisition, extensions due to continuing development of, and updates to development plans for the Oil Sands segment, and technical revisions due to improvements to recovery performance at Sunrise and Lloydminster thermal. These increases were partially offset by current year production and negative technical revisions resulting from recovery factor changes at Christina Lake and Foster Creek, and a minor disposition at Lloydminster thermal.
- Light and medium oil gross total proved and gross total proved plus probable reserves decreased by four million barrels and 10 million barrels, respectively. The changes were due to current year production and negative technical revisions due to updates to the Conventional segment development plans. These decreases were partially offset by extensions due to updates to the Conventional segment development plans.
- NGLs gross total proved and gross total proved plus probable reserves decreased by 10 million barrels and 20 million barrels, respectively. The changes were due to current year production, negative technical revisions due to updates to the Conventional segment development plans and negative technical revisions due to reductions to recovery performance in Indonesia. These reductions were partially offset by extensions due to updates to the Conventional segment development plans and technical revisions due to improvements to recovery performance in China.

- Conventional natural gas gross total proved and gross total proved plus probable reserves decreased by 205 billion cubic feet and 399 billion cubic feet, respectively. The changes were due to current year production, negative technical revisions due to updates to the Conventional segment development plans and negative technical revisions due to reductions to recovery performance in Indonesia. These reductions were partially offset by extensions due to updates to the Conventional segment development plans, technical revisions due to increases to original natural gas in place volumes in China and minor acquisitions in the Conventional segment.

The reserves data is presented as at December 31, 2025, using an average of the forecast prices, inflation and exchange rates ("Average Forecast") by McDaniel & Associates Consultants Ltd., GLJ Ltd. and Sproule ERCE. The Average Forecast is dated January 1, 2026. Comparative information as at December 31, 2024, uses the January 1, 2025, Average Forecast.

Additional information with respect to the evaluation and reporting of our reserves in accordance with NI 51-101 is contained in our AIF for the year ended December 31, 2025. Our AIF is available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov and on our website at cenovus.com. Material risks and uncertainties associated with estimates of reserves are discussed in the Risk Management and Risk Factors section of this MD&A and the Advisory.

LIQUIDITY AND CAPITAL RESOURCES

Our capital allocation framework enables us to preserve our balance sheet, provide flexibility in both high and low commodity price environments, and deliver value to shareholders.

We expect to fund our near-term cash requirements through cash from operating activities, the prudent use of our cash and cash equivalents, and other sources of liquidity. Our other sources of liquidity include draws on our committed credit facility, draws on our uncommitted demand facilities, and other corporate and financial opportunities, which provide timely access to funding to supplement cash flow. We remain committed to maintaining our investment grade credit ratings at S&P Global Ratings, Moody's Ratings, Morningstar DBRS and Fitch Ratings. The cost and availability of borrowing, and access to sources of liquidity and capital are dependent on current credit ratings and market conditions.

($ millions)	**2025**	2024
Cash From (Used In)		
Operating Activities	**8,228**	9,235
Investing Activities	**(7,677)**	(5,126)
Net Cash Provided (Used) Before Financing Activities	**551**	4,109
Financing Activities	**(749)**	(3,505)
Effect of Foreign Exchange on Cash and Cash Equivalents	**(155)**	262
Increase (Decrease) in Cash and Cash Equivalents	**(353)**	866

As at December 31, ($ millions)	**2025**	2024
Cash and Cash Equivalents	**2,740**	3,093
Total Debt	**11,032**	7,707

Cash From (Used in) Operating Activities

In 2025, cash from operating activities decreased compared with 2024, primarily due to changes in non-cash working capital, partially offset by lower current tax expense and lower cash-settled long-term incentive costs. Non-cash working capital decreased cash from operating activities by $363 million, primarily due to an increase in accounts receivable, and decreases in accounts payable and income tax payable, partially offset by a decrease in inventories, excluding the impact of the MEG Acquisition and the WRB Divestiture.

In 2024, the change in non-cash working capital was a source of cash of $1.3 billion due to lower accounts receivable, higher accounts payable and higher taxes payable, partially offset by higher inventories.

Cash From (Used in) Investing Activities

Cash used in investing activities increased in 2025 compared with 2024. Cash used in investing activities primarily relates to capital investment and the MEG Acquisition, partially offset by proceeds from the WRB Divestiture.

Cash From (Used in) Financing Activities

In 2025, cash used in financing activities was $749 million, compared with $3.5 billion in 2024, primarily due to the redemption of certain senior unsecured notes and higher share purchases under the Company's NCIB, partially offset by an increase in long-term debt from the receipt of a $2.7 billion term loan facility and the issuance of $2.6 billion of senior unsecured notes.

Working Capital

Working capital as at December 31, 2025, was $3.6 billion (December 31, 2024 – $3.1 billion). The increase was primarily driven by higher accounts receivable and lower accounts payable, partially offset by lower inventories.

We anticipate that we will continue to meet our payment obligations as they come due.

Returns to Shareholders Target

Maintaining a strong balance sheet, with the resilience to withstand price volatility and capitalize on opportunities throughout the commodity price cycle, is a key element of Cenovus's capital allocation framework. Our Net Debt target is $4.0 billion and represents a Net Debt to Adjusted Funds Flow ratio target of approximately 1.0 times at the bottom of the commodity pricing cycle, which we believe is a WTI price of approximately US$45.00 per barrel.

Upon closing of the MEG Acquisition, we adjusted our shareholder returns framework as follows:

- While Net Debt is above $6.0 billion, the Company will target to return approximately 50 percent of Excess Free Funds Flow to shareholders, with the remainder allocated to deleveraging.
- When Net Debt is between $6.0 billion and $4.0 billion, the Company will target to return approximately 75 percent of Excess Free Fund Flow to shareholders, with the remainder allocated to deleveraging.

Our long-term Net Debt target of $4.0 billion remains unchanged, and upon reaching the targeted levels, we plan to return approximately 100 percent of Excess Free Funds Flow to shareholders over time while stewarding Net Debt near $4.0 billion. Working capital movements, foreign exchange rate changes and other factors may result in periods where shareholder returns are less than, or exceed, Excess Free Funds Flow and Net Debt is above or below our target. The allocation of Excess Free Funds Flow to shareholder returns may be accelerated, deferred or reallocated between quarters at Management's discretion.

As at December 31, 2025, our Net Debt position was $8.3 billion and, as a result, our returns to shareholders target for the three months ended March 31, 2026, will be 50 percent of the first quarter's Excess Free Funds Flow.

Short-Term Borrowings

There were no direct borrowings on our uncommitted demand facilities as at December 31, 2025, or December 31, 2024. On September 30, 2025, Cenovus completed the WRB Divestiture, which included the Company's proportionate share of the WRB uncommitted demand facilities outstanding of US$225 million (C$313 million). Cenovus's proportionate share of the WRB uncommitted demand facilities outstanding as at December 31, 2024, was US$120 million (C$173 million).

Long-Term Debt, Including Current Portion

As at December 31, ($ millions)	**2025**	2024
Term Loan Facility	**2,700**	—
U.S. Dollar Denominated Senior Unsecured Notes	**5,887**	5,470
Canadian Dollar Senior Unsecured Notes	**2,450**	2,000
Total Debt Principal	**11,037**	7,470

Upon maturity on July 15, 2025, the Company repaid its 5.38 percent senior unsecured notes with a principal of US$133 million, in full.

We obtained a $2.7 billion term loan facility maturing on February 28, 2029, to fund a portion of the cash consideration for the MEG Acquisition. Upon closing of the MEG Acquisition, we assumed MEG's U.S. dollar senior unsecured notes with a principal of US$600 million. The notes were subsequently redeemed on December 1, 2025, in full.

On November 20, 2025, the Company closed public offerings in Canada and the U.S. of senior unsecured notes of $2.6 billion, composed of $650 million 4.25 percent notes due in 2033, $550 million 4.60 percent notes due in 2035, US$500 million 4.65 percent notes due in 2031 and US$500 million 5.40 percent notes due in 2036.

On December 1, 2025, the Company redeemed its 4.25 percent senior unsecured notes with a principal of US$373 million, in full. On December 22, 2025, the Company redeemed its 3.60 percent senior unsecured notes with a principal of $750 million, in full.

As at December 31, 2025, we were in compliance with all of the terms of our debt agreements, which includes the terms of our committed credit facility and term loan facility. We are required to maintain a debt to capitalization ratio, as defined in the debt agreements, not to exceed 65 percent. We are below this limit.

Available Sources of Liquidity

The following sources of liquidity are available as at December 31, 2025:

($ millions)	Maturity	Amount Available
Cash and Cash Equivalents	**n/a**	**2,740**
Committed Credit Facility [(1)]		
Revolving Credit Facility – Tranche A	**September 19, 2029**	**3,300**
Revolving Credit Facility – Tranche B	**September 19, 2028**	**2,200**
Uncommitted Demand Facilities [(2)]	**n/a**	**1,116**

(1) No amounts were drawn on the committed credit facility as at December 31, 2025 (December 31, 2024 – $nil).

(2) Represents amounts available for cash draws. Our uncommitted demand facilities include $1.5 billion, of which $1.4 billion may be drawn for general purposes, or the full amount can be available to issue letters of credit. As at December 31, 2025, there were outstanding letters of credit aggregating to $341 million (December 31, 2024 – $355 million) and no direct borrowings (December 31, 2024 – $nil).

On September 19, 2025, Cenovus renewed its existing committed credit facility to extend the maturity dates by more than one year. As at December 31, 2025, the committed credit facility consists of a $3.3 billion tranche maturing on September 19, 2029, and a $2.2 billion tranche maturing on September 19, 2028. As at December 31, 2025, no amount was drawn on the credit facility (December 31, 2024 – $nil).

Base Shelf Prospectus

On November 28, 2025, Cenovus filed a base shelf prospectus that allows the Company to offer, from time to time, debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere as permitted by law. The base shelf prospectus will expire in December 2028. Offerings under the base shelf prospectus are subject to market conditions on terms set forth in one or more prospectus supplements.

Financial Metrics

We monitor our capital structure and financing requirements using, among other things, Total Debt, the Net Debt to Adjusted EBITDA ratio, the Net Debt to Adjusted Funds Flow ratio and the Net Debt to Capitalization ratio. Refer to Note 22 of the Consolidated Financial Statements for further details.

We define Net Debt as short-term borrowings and the current and long-term portions of long-term debt, net of cash and cash equivalents, and short-term investments. The components of the ratios include Capitalization, Adjusted Funds Flow and Adjusted EBITDA. We define Capitalization as Net Debt plus Shareholder's Equity. We define Adjusted Funds Flow, as used in the Net Debt to Adjusted Funds Flow ratio, as cash from (used in) operating activities, less settlement of decommissioning liabilities and net change in operating non-cash working capital calculated on a trailing twelve-month basis. We define Adjusted EBITDA, as used in the Net Debt to Adjusted EBITDA ratio, as net earnings (loss) before finance costs, net, income tax expense (recovery), DD&A, E&E asset write-downs, goodwill impairments, (income) loss from equity-accounted affiliates, unrealized (gain) loss on risk management, net foreign exchange (gain) loss, (gain) loss on divestiture of assets, re-measurement of contingent payments and other (income) loss, net calculated on a trailing twelve-month basis. These ratios are used to steward our overall debt position and are measures of our overall financial strength.

As at December 31,	**2025**	2024
Net Debt to Adjusted EBITDA Ratio (times)	**0.9**	0.5
Net Debt to Adjusted Funds Flow Ratio (times)	**0.9**	0.6
Net Debt to Capitalization Ratio (percent)	**21**	13

Our Net Debt to Adjusted EBITDA ratio and our Net Debt to Adjusted Funds Flow ratio targets are approximately 1.0 times and Net Debt at or below $4.0 billion over the long-term at a WTI price of US$45.00 per barrel. These measures may fluctuate periodically outside this range due to factors such as persistently high or low commodity prices or the strengthening or weakening of the Canadian dollar relative to the U.S. dollar. Our objective is to maintain a high level of capital discipline and manage our capital structure to help ensure we have sufficient liquidity through all stages of the economic cycle. To ensure financial resilience, we may, among other actions, adjust capital and operating spending, steward working capital, draw down on our credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase our common or preferred shares for cancellation, issue new debt, or issue new shares.

Our Net Debt to Adjusted EBITDA ratio, Net Debt to Adjusted Funds Flow ratio and Net Debt to Capitalization ratio as at December 31, 2025, increased compared with December 31, 2024, primarily as a result of higher Net Debt. See the Operating and Financial Results section of this MD&A for more information on changes in Net Debt.

Share Capital and Stock-Based Compensation Plans

Our common shares are listed on the Toronto Stock Exchange ("TSX") and New York Stock Exchange ("NYSE"). Our cumulative redeemable preferred shares series 1 and 2 are listed on the TSX. On March 31, 2025, and June 30, 2025, Cenovus exercised its right to redeem all 8.0 million of the Company's series 5 preferred shares and all 6.0 million of the Company's series 7 preferred shares, respectively. The preferred shares were redeemed at a price of $25.00 per share for a total of $350 million.

As at December 31, 2025, there were approximately 1,883.4 million common shares outstanding (December 31, 2024 – 1,825.0 million common shares) and 12.0 million preferred shares outstanding (December 31, 2024 – 26.0 million preferred shares). Total purchase consideration for the MEG Acquisition included the issuance of 143.9 million Cenovus common shares. Refer to Note 4 of the Consolidated Financial Statements for further details.

Cenovus has established an employee benefit plan trust (the "Trust"). The Trust, through an independent trustee, acquires Cenovus's common shares on the open market, which are held to satisfy the Company's obligations under certain stock-based compensation plans. For the year ended December 31, 2025, the Trust purchased 7.1 million common shares (2024 – 2.0 million common shares) for a total of $155 million (2024 – $43 million) and distributed 3.8 million common shares (2024 – nil) for a total of $82 million (2024 – $nil) under the employee benefit plan. As at December 31, 2025, there were 5.3 million common shares held by the Trust (December 31, 2024 – 2.0 million common shares). Refer to Note 26 of the Consolidated Financial Statements for further details.

As at December 31, 2025, there were approximately 1.2 million common share purchase warrants ("Cenovus Warrants") outstanding (December 31, 2024 – 3.6 million). Each Cenovus Warrant entitled the holder to acquire one common share for a period of five years from the date of issue at an exercise price of $6.54 per common share. The Cenovus Warrants expired on January 1, 2026. Refer to Note 26 of the Consolidated Financial Statements for further details.

Refer to Note 28 of the Consolidated Financial Statements for further details on our stock option plans and our performance share unit, restricted share unit and deferred share unit plans. Our outstanding share data is as follows:

As at February 13, 2026	**Units Outstanding** (thousands)	**Units Exercisable** (thousands)
Common Shares	**1,879,261**	**n/a**
Series 1 First Preferred Shares	**10,740**	**n/a**
Series 2 First Preferred Shares	**1,260**	**n/a**
Stock Options	**10,626**	**4,647**
Other Stock-Based Compensation Plans	**21,089**	**1,832**

Common Share Dividends

In 2025, we declared and paid base dividends of $1.4 billion or $0.780 per common share (2024 – $1.3 billion or $0.680 per common share) and variable dividends of $nil (2024 – $251 million or $0.135 per common share).

On February 18, 2026, the Board declared a first quarter base dividend of $0.200 per common share. The dividend is payable on March 31, 2026, to common shareholders of record as at March 13, 2026.

The declaration of common share dividends is at the sole discretion of the Board and is considered quarterly.

Cumulative Redeemable Preferred Share Dividends

($ millions)	**2025**	2024
Series 1 First Preferred Shares	**7**	7
Series 2 First Preferred Shares	**1**	2
Series 3 First Preferred Shares	**—**	12
Series 5 First Preferred Shares	**2**	9
Series 7 First Preferred Shares	**4**	6
Total Preferred Share Dividends Declared	**14**	36

For the year ended December 31, 2025, dividends of $14 million were paid on the preferred shares (2024 – $45 million).

On February 18, 2026, the Company's Board of Directors declared first quarter preferred share dividends of $2 million payable on March 31, 2026, to preferred shareholders of record as at March 13, 2026.

The declaration of preferred share dividends is at the sole discretion of the Board and is considered quarterly.

Share Repurchases

On November 7, 2025, the Company received approval from the TSX to renew the Company's NCIB program to purchase up to 120.3 million common shares during the period from November 11, 2025, to November 10, 2026.

	2025	2024
Common Shares Purchased and Cancelled Under NCIB (millions of common shares)	**89.4**	55.9
Weighted Average Price per Common Share ($)	**21.87**	25.38
Purchase of Common Shares Under NCIB ($ millions)	**1,995**	1,445

From January 1, 2026, to February 13, 2026, the Company purchased an additional 5.0 million common shares for $126 million. As at February 13, 2026, the Company can further purchase up to 107.9 million common shares under the NCIB.

Contractual Commitments and Obligations

We have obligations for goods and services entered into in the normal course of business. Obligations that have original maturities of less than one year are excluded from our total commitments disclosed below. For further information, see Note 34 to the Consolidated Financial Statements.

As at December 31, 2025

($ millions)	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Commitments							
Transportation and Storage [(1) (2)]	2,603	2,623	2,775	2,802	2,531	23,591	**36,925**
Real Estate	64	65	65	69	70	474	**807**
Obligation to Fund HCML	99	94	54	42	41	59	**389**
Other Long-Term Commitments	547	184	151	117	111	484	**1,594**
Total Commitments	3,313	2,966	3,045	3,030	2,753	24,608	**39,715**
Long-Term Debt (Principal and Interest)	473	489	1,717	3,303	330	9,718	**16,030**
Lease Liabilities (Principal and Interest) [(3)]	519	485	437	371	317	2,719	**4,848**
Decommissioning Liabilities	222	228	210	232	257	7,568	**8,717**
Total Commitments and Obligations	4,527	4,168	5,409	6,936	3,657	44,613	**69,310**

(1) Includes transportation commitments that are subject to regulatory approval or were approved but are not yet in service of $7.7 billion (December 31, 2024 – $854 million), of which $1.6 billion were assumed from the MEG Acquisition. Terms are up to 15 years on commencement.

(2) As at December 31, 2025, includes $1.7 billion related to transportation and storage commitments with HMLP (December 31, 2024 – $1.8 billion).

(3) Lease contracts related to office space, a pipeline, storage tanks, terminals, railcars, vessels, refining equipment, a natural gas processing plant, caverns, fleet vehicles, our commercial fuels network and other field equipment.

Through the MEG Acquisition, the Company assumed $8.3 billion of various transportation and storage commitments.

As at December 31, 2025, outstanding letters of credit issued as security for performance under certain contracts totaled $341 million (December 31, 2024 – $355 million).

Legal Proceedings

We are involved in a limited number of legal claims associated with the normal course of operations. We believe that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on our Consolidated Financial Statements.

Transactions with Related Parties

Husky Midstream Limited Partnership

The Company holds a 35 percent interest in and is the operator of HMLP. The Company charges HMLP for construction and management services, and incurs costs for the use of HMLP's pipeline systems, as well as transportation and storage services. Access fees and transportation and storage services are based on contractually agreed rates with HMLP.

($ millions)	**2025**	2024
Revenues from Construction and Management Services	**164**	155
Transportation Expenses	**258**	278

For the year ended December 31, 2025, the Company received $40 million of distributions from HMLP (2024 – $65 million) and paid $2 million in contributions (2024 – $51 million).

Husky-CNOOC Madura Limited

Cenovus holds a 40 percent equity interest in the jointly-controlled entity HCML. For the year ended December 31, 2025, the Company received $94 million of distributions from HCML (2024 – $107 million) and paid $nil in contributions (2024 – $nil).

RISK MANAGEMENT AND RISK FACTORS

Risk Governance

Our Enterprise Risk Management ("ERM") program drives the identification, measurement, prioritization, and management of our risks and is integrated with the Cenovus Operations Integrity Management System ("COIMS"). We continuously monitor our risk profile and industry best practices. The ERM Policy, approved by our Board, outlines our risk management principles, expectations, and the roles and responsibilities of all staff. Our risk management framework aligns with International Organization for Standardization ("ISO") in its ISO 31000 – Risk Management Guidelines. The results of our ERM program are documented in consolidated risk reports presented to our Board and through regular updates.

Risk Factors

We are exposed to various risks through the pursuit of our strategic objectives. Some of these risks impact the energy industry as a whole and others are unique to our operations. The following discussion describes the financial, operational, regulatory, environmental, reputational, climate-change related and other risks to Cenovus. Each risk identified in this MD&A may individually, or in combination with other risks, have a material impact on, among other things, our business, financial condition, results of operations, cash flows, reputation, ability to pursue our strategic priorities, meet our targets or outlooks, goals, initiatives and ambitions, ability to respond to changes in our operating environment, access to capital, cost of borrowing, access to liquidity, ability to fund share repurchases, dividend payments and/or business plans, fulfill our obligations and/or the market price of our securities. These factors should be considered when investing in securities of Cenovus.

Financial Risk

Commodity Prices

Our financial performance is significantly dependent on prevailing commodity prices. Prices for crude oil, refined products, natural gas, NGLs and other related products are impacted by a number of factors, including, but not limited to: global and regional supply of, and demand for, these commodities; the ability of producers and governments to replace supply; processing and export capacity; export or import restrictions; domestic and global economic conditions; inflation; changes to interest rates; the impact of tariffs and responses thereto (including by governments, our trade partners and customers), which may include, without limitation, counter-tariffs, surtaxes, countermeasures, countervailing duties, antidumping duties, special duties, export taxes on Cenovus's products, and restrictions on imports and exports, such as export controls, sanctions or other measures; central bank policies; market competitiveness; the actions of OPEC and other oil exporting nations, including, but not limited to, compliance or non-compliance with quotas agreed upon by OPEC members and decisions by OPEC regarding whether and to what extent to impose production quotas on its members; developments related to the market for these commodities; inventory levels of these commodities; seasonal trends; refinery availability; current and potential future environmental laws and regulations; emissions, including, but not limited to, carbon; market pricing and the accessibility and liquidity of these and related markets; prices and availability of alternate sources of energy; actions of governments and regulatory bodies; enforcement of laws and regulations; shifts or changes in governmental policy; public sentiment towards the use of non-renewable resources; political instability and social conditions in countries producing these commodities; market access constraints and transportation restrictions or interruptions; terrorist threats; technological developments; economic sanctions; outbreak of a pandemic, war or other international or regional conflict and any related government action or military exercise; the occurrence of natural disasters; and weather conditions.

The focus on the timing and pace of the transition to a lower-carbon economy and resulting trends will likely continue to affect global energy demand and usage, including the composition of the types of energy generally used by industry and individual consumers. Under certain aggressive low-carbon scenarios, potential demand erosion could contribute to commodity price fluctuations and structural commodity price declines. However, it is not currently possible to predict the timelines for, and precise effects of, the transition to a lower-carbon economy.

The financial performance of our oil sands operations could also be impacted by discounted or reduced commodity prices for our oil sands production relative to certain international benchmark prices, due, in part, to potential constraints on the ability to transport and sell products to domestic and international markets, and the quality of crude oil produced. Of particular importance to us are condensate cost and supply, and the price differentials between bitumen and both light to medium crude oil and heavy crude oil. Bitumen is more expensive for refineries to process and therefore generally trades at a discount to the market price for light to medium crude oil and heavy crude oil, which, along with higher condensate costs, can adversely affect our financial condition.

The financial performance of our refining operations is impacted by the relationship, or margin, between refined product prices and the prices of refinery feedstock. Refining margins are subject to factors such as, but not limited to, prices of refinery feedstock; capacity and utilization rates at existing refineries; global and regional demand for refined products; market conditions for refined products; and seasonal demand. Sales volumes, prices, inventory levels and inventory values will fluctuate accordingly. Future refining margins are uncertain and decreases in refining margins may have a negative impact on our business, results of operations, cash flows and financial condition.

All of these factors are beyond our control and can result in a high degree of both cost and price volatility.

We integrate the potential impact of a variety of factors and scenarios into our business planning processes, including commodity price fluctuations, climate change and GHG regulations, including the cost of carbon. To mitigate uncertainty, we evaluate our business plans under a range of scenarios. Although Management believes that our assumptions and estimates are reasonable, reflect current, pending and potential future states and are informed by external scenarios, they are based on numerous assumptions and estimates that, if false, may have a material adverse effect on our business, financial condition and results of operations. As such, variations between actual outcomes and our assumptions and estimates may have a material adverse effect on our business, financial condition, results of operations, reputation and cash flows.

Fluctuations in commodity prices, associated price differentials and refining margins may impact our financial condition, results of operations, cash flows, growth, access to capital, cost of borrowing, ability to meet guidance targets, the value of our assets, the level of shareholder returns, and ability to maintain our business and fund projects. A substantial decline in these commodity prices or an extended period of low commodity prices may result in: an inability to meet all our financial obligations as they come due; a delay or cancellation of existing or future drilling, development or construction programs; curtailment in production; unutilized long-term transportation commitments; and/or low utilization levels at our refineries.

The commodity price risks noted above, as well as other risks such as market access constraints and transportation restrictions, reserves replacement and reserves estimates, and cost management that are more fully described herein, may have a material impact on our business, financial condition, results of operations, cash flows and reputation, and may, along with the comparison of the carrying value of our assets to our market capitalization, be considered indicators of impairment.

As discussed in this MD&A, we conduct an assessment, at each reporting date, of the carrying value of our assets in accordance with IFRS Accounting Standards. If crude oil, refined product, natural gas and NGL prices decline significantly and remain at low levels for an extended period, or if the costs to develop or produce such resources significantly increase, the carrying value of our assets may be subject to impairment and our net earnings could be adversely affected.

Risks Associated with Tariffs and International Trade

Discussions continue regarding current and future economic arrangements between Canada and the U.S., and the U.S.'s relationships with other global trading partners, and there remains significant uncertainty over whether tariffs, surtaxes, or other restrictive trade measures or countermeasures will be implemented or maintained and, if so, the scope, impact, and duration of any such measures. Potential measures could include, among others, increased tariffs on Canadian energy imports into the U.S. or other jurisdictions, controls or restrictions on cross-border supply chains, changes to existing preferential trade agreements such as the United States-Mexico-Canada Agreement or cross-border energy agreements, or additional regulatory barriers that could impact our ability to access international markets and conduct business efficiently.

Restrictive trade measures or countermeasures, if implemented for any period of time, could have a significant impact on the market for crude oil, NGLs, natural gas and refined petroleum products in North America and internationally and could result in, among other things, a high degree of both cost and price volatility, a relative weakening of the Canadian dollar, widening differentials, and decreased demand for our products and services. Any or all such effects may have a material adverse impact on our business, results of operations and financial condition.

Additionally, restrictive trade measures or countermeasures or export controls imposed on our products or operations could reduce our ability to compete in the global market. We also rely on the importation of specialized equipment, raw materials and technology from various global suppliers. Any restrictions, controls, or increases in tariffs on these goods could lead to higher costs for these essential inputs, thereby having a negative effect on our financial position and cash flows.

Risks Associated with Financial Risk Management Activities

Our Board-approved Market Risk Management Policy allows Management to use approved derivative financial instruments as needed, within authorized limits, to help mitigate the impact of changes in crude oil and condensate prices and differentials, NGLs and natural gas spreads, basis and prices, electricity prices, refined product, and crack spread margins, as well as fluctuations in foreign exchange and interest rates. We may also use derivative instruments and physical positions in various operational markets to help optimize our supply costs or sales of our production, or fixed-price commitments for the purchase or sale of crude oil, refined products, natural gas, NGLs and other related products.

Notwithstanding the anticipated benefits of undertaking these risk management and trading activities, the use thereof may expose us to risks which may cause significant loss, including risks related to: changes in the valuation of the risk management instrument being poorly correlated to the change in the valuation of the underlying exposures; change in price of the underlying commodity or market value of the instrument or physical position; lack of market liquidity; insufficient counterparties to transact with; counterparty default; deficiency in systems or controls; human error; the unenforceability of contracts; and any inability to fulfill our delivery obligations related to the underlying physical transaction. These financial instruments may also limit the benefit to us of commodity prices, interest or foreign exchange rate changes.

Additionally, Cenovus may engage in trading activities other than for hedging purposes. These activities, including the trading of energy products, are exposed to market variables and commodity price risk. As part of these activities, the Company may enter into physical contracts and other financial instruments. Such trading activities may expose Cenovus to additional risks including: market price risk; liquidity risk; counterparty risk; and increased earnings volatility.

For details of our financial instruments, including classification, assumptions made in the calculation of fair value and additional discussion on exposure of risks and the management of those risks, see Notes 31 and 32 of the Consolidated Financial Statements.

Impact of Financial Risk Management Activities

Cenovus may employ various price alignment and volatility management strategies, including financial risk management contracts, to reduce volatility in future cash flows and improve cash flow stability.

Transactions typically span across numerous time periods. As such, these transactions reside across both realized and unrealized risk management. As the financial contracts settle, they will flow from unrealized to realized risk management gains and losses.

The discussion below summarizes the sensitivities of the fair value of our risk management positions to fluctuations in commodity prices and foreign exchange rates, with all other variables held constant. Management believes the price fluctuations identified below are a reasonable measure of volatility. The impact of the below on the Company's open risk management positions could result in an unrealized gain (loss) impacting earnings before income tax as follows:

As at December 31, 2025	Sensitivity Range	Increase	Decrease
Crude Oil and Condensate Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	—	—
Crude Oil and Condensate Differential Price [1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	**1**	**(1)**
WCS (Hardisty) Differential Price	± US$2.50/bbl Applied to WCS Differential Hedges Tied to Production	**13**	**(13)**
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	**(4)**	**4**
Natural Gas Commodity Price	± US$0.50/Mcf Applied to Natural Gas Hedges Tied to Production	—	—
Natural Gas Basis Price	± US$0.50/Mcf Applied to Natural Gas Basis Hedges	—	—
Power Commodity Price	± C$10.00/MWh [2] Applied to Power Hedges	**39**	**(39)**

(1) Excluding WCS at Hardisty.
(2) One thousand kilowatts of electricity per hour ("MWh").

For further information on our risk management positions, see Notes 31 and 32 of the Consolidated Financial Statements.

Credit, Liquidity and Availability of Future Financing

The future development of our business may be dependent on our ability to access external capital, including, but not limited to, debt and equity financing. Among other things, unpredictable financial markets, a sustained commodity price downturn or significant unanticipated expenses, or a change in law, market fundamentals, our credit ratings, business operations or investor or lender policy or sentiment, may impede our ability to secure and maintain cost-effective financing.

Our ability to access capital and secure insurance coverage, at reasonable costs, or at all, is limited by the capacity of the applicable markets, which may be adversely affected if investors, insurers, or other relevant stakeholders adopt more restrictive decarbonization policies.

An inability to access capital on terms acceptable to us, or at all, could affect our ability to make future capital expenditures, to maintain desirable financial ratios and to meet our financial obligations as they come due, potentially resulting in a material adverse effect on our business, financial condition, results of operations, cash flows, ability to comply with various financial and operating covenants, credit ratings and reputation.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic, business, regulatory, market and other conditions, some of which are beyond our control. If our operating and financial results are not sufficient to service current or future indebtedness, we may take actions such as: reducing or suspending share repurchases; reducing or suspending dividends; reducing or delaying business activities, investments or capital expenditures; selling assets; restructuring or refinancing our debt; or seeking additional capital that could have less favourable terms.

We are required to comply with various financial and operating covenants under our credit facility and the indentures governing our debt securities. Non-compliance with these covenants may lead to restrictions on access to capital or accelerated repayment.

Credit Ratings

A downgrade in any of our credit ratings, a negative change in the Company's credit ratings outlook, or the withdrawal of a rating by a rating agency could adversely affect the cost and availability of borrowing, access to sources of liquidity and capital, and our business relationships with counterparties, operating partners and suppliers. Credit ratings are based on our financial and operational strength and several factors not entirely within our control, including, but not limited to, conditions affecting the oil and gas and refining industries generally, industry risks associated with the transition to a lower-carbon economy, government policies and the general state of the economy.

If one or more of our credit ratings falls below certain ratings thresholds, we may be obligated to post additional collateral in the form of cash, letters of credit or other financial instruments to establish or maintain business arrangements. Failure to provide adequate credit risk assurance to counterparties and suppliers may result in foregoing opportunities or having contracts terminated.

Exposure to Counterparties

In the normal course of business, we enter into contracts with suppliers, partners, lenders, customers and other counterparties. If such parties do not fulfill their contractual obligations on a timely basis or at all, we may suffer financial losses or delays to our development plans, or we may have to forego other opportunities, all of which could materially impact our business, results of operations and financial condition.

Foreign Exchange Rates

Cenovus's revenues are predominantly based on U.S. dollar benchmark prices, and a significant portion of our long-term debt and interest expense is denominated in U.S. dollars, while many of our operating and capital costs are in Canadian dollars. A portion of our long-term sales contracts in Asia Pacific are priced in RMB. Fluctuations in foreign exchange rates, particularly the U.S./Canadian dollar and RMB/Canadian dollar, may affect our results and could have a material adverse effect on our cash flows and financial condition.

Interest Rates

Fluctuations in interest rates could negatively affect Cenovus's financial performance. This risk arises during the refinancing of maturing long-term debt, when issuing new debt, or through changes in borrowing costs on floating-rate instruments. We are also exposed to interest rate variability on existing credit facilities used to support liquidity. Additionally, shifts in interest rates could change our net finance costs and could impact how certain liabilities are recorded. Collectively, these factors could have an impact on Cenovus's financial results.

Dividend Payments and Purchase of Securities

The payment of dividends, whether base, variable or preferred, the continuation of our dividend reinvestment plan and any potential purchase by Cenovus of our securities is at the discretion of our Board and is dependent upon, among other things, financial performance, debt covenants, satisfying solvency tests, our ability to meet financial obligations as they come due, working capital requirements, future tax obligations, future capital requirements, commodity prices and other risks identified in the Risk Management and Risk Factors section of this MD&A. The frequency and amount of variable dividend payments, if any, may vary significantly over time as a result of our Net Debt and Excess Free Funds Flow, amount of share buybacks and other factors inherent within our capital allocation framework, including Management's discretion to accelerate, defer or reallocate any Excess Free Funds Flow to shareholder returns between quarters. Our Net Debt and Excess Free Funds Flow may vary as a result of, among other things, our business plans, results of operations, acquisitions and dispositions, financial condition and impact of any of the risks identified in the Risk Management and Risk Factors section of this MD&A. The Company can provide no assurance that it will continue to pay base or variable dividends or authorize share buybacks at the current rate, or at all, as any share repurchases and payment of dividends is at the discretion of our Board.

Disclosure Controls and Procedures ("DC&P") and Internal Control Over Financial Reporting ("ICFR")

Based on their inherent limitations, DC&P and ICFR may not prevent or detect misstatements, and even those controls determined to be effective can only provide reasonable assurance with respect to financial statement preparation and presentation. Failure to adequately prevent, detect and correct misstatements could have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

Management has limited the scope of the design of DC&P and ICFR for the business acquired from MEG for the current reporting period, as permitted under National Instrument 52-109, *"Certification and Disclosure in Issuers' Annual and Interim Filings"* ("NI 52-109"). Management continues to integrate the acquired operations and expects to complete its assessment and alignment of DC&P and ICFR with Cenovus's control environment during 2026. For further details, see the Control Environment section of this MD&A.

Operational Risk

Operational Considerations (Safety, Environment and Reliability)

Our operations are subject to risks generally affecting the oil and gas and refining industries and normally incidental to: (i) the storing, transporting, processing and marketing of crude oil, refined products, natural gas, NGLs and other related products; (ii) the drilling and completion of crude oil and natural gas wells; (iii) the operation and development of crude oil and natural gas properties; (iv) the operation of refineries, terminals, pipelines and other transportation and distribution facilities, including at facilities operated by our partners or third parties; and (v) the development and operation of projects relating to our sustainability goals, including carbon capture, utilization and storage projects. These risks include, but are not limited to: the effects of government actions, laws or regulations, policies and initiatives, including as a result of new or existing administrations in the jurisdictions in which we conduct operations, development or exploration; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; fires; flooding; geologic activity arising from fracking or carbon capture, utilization and storage projects; explosions; blowouts; loss of containment; gaseous leaks; power outages; migration of harmful substances into water systems; releases or spills, including releases or spills from offshore operations, shipping vessels or other marine transport incidents; aviation, railcar or road transportation incidents; iceberg incidents; accidents or damage caused by third parties or otherwise occurring in the operation of our business; uncontrollable flows of crude oil, natural gas or well fluids; failure to follow operating procedures or operate within established operating parameters; adverse weather conditions including, but not limited to, adverse sea conditions, extreme weather events, wildfires and natural disasters; corrosion; pollution; freeze-ups and other similar events; the breakdown or failure of equipment, pipelines, facilities, wells and projects; the breakdown or failure of operational and information technology and systems and processes, any compromise thereof or released data; regular or unforeseen maintenance; equipment underperformance; failure to maintain adequate supplies of spare parts; operator error; shortages of skilled labour; labour disputes and strikes; disputes with owners or operators of interconnected facilities and carriers; planned or unplanned operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of such party's facilities and pipelines; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances; loss of product; price, quality and unavailability of feedstock, including condensate; epidemics or pandemics; protests, blockades or other acts of activism; geopolitical factors including but not limited to war, vandalism or terrorism, or other regional or international conflict or action; and catastrophic events, including, but not limited to, accidents or hazards that may occur at or during transport to or from commercial or industrial sites.

Climate change may result in an increased level of operational risk requiring increased or additional mitigation measures. Systemic climatic changes or extreme climatic conditions may increase our exposure to, and magnitude of, the impact of physical climate risks, such as floods, drought, wildfires, earthquakes, hurricanes, typhoons, storms, extreme temperatures and other extreme weather events or natural disasters. Severe weather conditions may result in an operational incident with the potential to result in spills, asset damage and production, refining disruption or safety and reliability of operations.

If any such risks materialize, they may: interrupt operations; impair our ability to achieve our sustainability goals; cause loss of life or personal injury; result in loss of or damage to equipment, property, operational and information technology and control systems and data, which may result in reduced revenue from reduced capacity or business interruption, or increased costs related to asset repair; cause environmental damage that may include polluting water, land or air; cause reputational damage; and may result in regulatory action, fines, penalties, civil suits or criminal or regulatory charges against us, any of which may have a material adverse effect on our business, financial condition, results of operations, cash flows and reputation.

We maintain a comprehensive insurance program in respect of our assets and operations. However, not all potential occurrences and disruptions in respect of our assets or operations are insured or are insurable, and we cannot guarantee that our insurance coverage will be available or sufficient to fully cover any claims that may arise from such occurrences or disruptions. The occurrence of an event that is not fully covered by our insurance program could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Market Access Constraints and Transportation Restrictions

Our production is transported through, and our refineries are reliant on various pipelines and terminals, as well as rail, marine and truck networks, to transport feedstock and refined products to and from third-party, or Cenovus, owned and/or operated, facilities. The impacts of tariffs and responses thereto (including by governments, our trade partners and customers), which may include, without limitation, tariffs, surtaxes, countermeasures, countervailing duties, antidumping duties, special duties, export taxes on Cenovus's products, and restrictions on imports and exports, such as export controls, sanctions or other measures, or disruptions in, or restricted availability of, pipeline, terminal, marine, rail or truck transport systems, could limit the ability to deliver production volumes and adversely affect commodity prices, sales volumes and/or the prices received for our products, projected production growth, upstream or refining operations and cash flows. These interruptions and restrictions may be caused or intensified by, among other things, the inability of the pipeline, terminal or marine, rail or truck networks to operate, or may be related to capacity constraints if supply into the system exceeds the infrastructure capacity. There can be no certainty that third-party pipeline projects for new or expanded capacity will be approved or constructed or that such projects would provide sufficient transportation capacity.

There is no certainty that rail, marine and truck transport and other alternative types of transportation for our production will be sufficient to address gaps caused by operational constraints on the pipeline system. In addition, our rail, marine and truck shipments may be impacted by service delays, changes to laws and regulations, labour issues, inclement weather, vessel, railcar or truck availability, geopolitical factors, war, terrorism, or other international or regional conflict, or other rail, marine or truck transport incidents and could adversely impact sales volumes or the price received for product, or impact our reputation or result in legal liability, loss of life or personal injury, loss of equipment or property or environmental damage. Should laws and regulations change, the costs of complying with those changes will likely be passed on to Cenovus and may adversely affect our ability to transport by rail, marine or truck or the economics associated with such transportation. Finally, planned or unplanned shutdowns, outages or closures of our refineries or third-party systems can limit our ability to receive or deliver product with negative implications on our business, financial condition, results of operations and cash flows.

Reserves Replacement

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels. Our business, reputation, financial condition, results of operations and cash flows are highly dependent upon successfully producing from current reserves and acquiring, discovering or developing additional reserves. Exploring for, developing or acquiring reserves is capital intensive. To the extent our cash flow is insufficient to fund capital expenditures and external sources of capital become limited or unavailable, our ability to make the necessary capital investments to maintain and expand our crude oil and natural gas reserves will be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

The production rate of oil and gas properties tends to decline as reserves are depleted, while the associated operating costs increase. Maintaining an inventory of developable projects to support future production of crude oil and natural gas depends on, among other things: obtaining and renewing rights to explore, develop and produce crude oil, refined products, natural gas, NGLs and other related products; drilling success; completing long-lead time capital intensive projects on budget and on schedule; and the application of successful exploitation techniques on mature properties.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable crude oil and natural gas reserves and associated future net cash flows and revenue are based on a number of variable factors and assumptions including, but not limited to: geological and engineering estimates; product prices; future operating and capital costs; historical production from the properties and the assumed effects of regulation by governmental agencies, including royalty payments and taxes, and environmental and emissions-related laws and regulations and taxes; initial production rates; production decline rates; and the availability, proximity and capacity of oil and gas gathering systems, pipelines, rail, truck and marine transportation and processing facilities, all of which may cause actual results to vary materially from estimates.

All such estimates are uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. The accuracy of any reserves estimate is a matter of interpretation and judgment and is a function of the quality and quantity of available data, which may have been gathered over time. For those reasons, estimates of the economically recoverable crude oil and natural gas reserves attributable to any particular group of properties, and classification of such reserves based on risk of recovery and estimates of future net revenue expected therefrom, as prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, taxes, and development and operating expenditures with respect to our reserves may vary from current estimates and such variances may be material.

Estimates with respect to reserves are often based on volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based on production history will result in variations in the estimated reserves, which may be material. The evaluation of reserves is a continuous process which can be significantly impacted by a variety of internal and external influences, and periodic revisions are required as a result of newly acquired technical data, technology improvements or changes in performance, pricing, economic conditions, market availability or regulatory requirements.

Non-Producing or Undeveloped Reserves

A significant portion of our bitumen reserves, as well as a portion of our light and medium oil, NGLs and conventional natural gas reserves, are classified as undeveloped and will require significant expenditures to render them capable of production. These reserves may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. As these reserves are non-producing and/or undeveloped, their estimation relies on geological and recovery performance analogs that assume success case outcomes that may not materialize. These reserves are expected to be developed over multiple decades, with decisions regarding the priority and timing of development depending on a range of factors, including economic conditions, government regulations such as production limits, observed reservoir performance, development plan optimization, facility capacity, pipeline constraints, the overall size of the development program and strategic considerations. As a result, developments may be delayed, advanced, or cancelled, and the associated reserves may be revised and/or reclassified or removed from the reserves base.

SAGD Bitumen Recovery Process

The SAGD bitumen recovery process is energy intensive and consumes significant amounts of natural gas in the production of steam that is used in the recovery process. The amount of steam required in the recovery process varies and therefore impacts natural gas and related emissions costs. Geological characteristics, in concert with the actual development and operating practices employed, directly influence the efficiency of steam chamber conformance and propagation. Variability in these factors can materially affect bitumen mobility, steam-oil ratios and recovery factors, which may differ materially from estimates informed by geological and recovery performance analogs, which are inherently less reliable than actual production history. Variability of any of these development or operational considerations may reduce production, increase costs or lead to revisions to reserves estimates or development plans. A large increase in costs could cause certain projects that rely on the SAGD bitumen recovery process to become economically challenged, which could have a negative effect on our business and financial condition.

Operational issues may adversely affect the stability and performance of the SAGD bitumen recovery process. The requirement to maintain reservoir integrity, under sustained steam-injection can impact production timing, costs and recovery performance. Operational issues and reservoir integrity related events, may result in production curtailments, increased costs, regulatory involvement or revisions to future development plans and reserve estimates.

Cost Management and Inflation

Development, operating and construction costs are affected by a number of factors including, but not limited to: development, adoption and success of new technologies, including those related to our GHG emissions reduction goals; inflationary price pressure; changes in regulatory compliance costs; scheduling delays; interruptions to existing market access infrastructure; failure to maintain quality construction and manufacturing standards; equipment limitations, including the cost or availability of oil and gas field equipment; commodity prices; higher steam-oil ratios in our Oil Sands operations; economic sanctions; restrictive trade measures or countermeasures; changing government policies (including but not limited to environmental policies), laws and regulations; supply chain disruptions, including force majeure; and access to skilled labour and critical third-party services. Such higher costs may not be fully offset through corresponding increases in commodity prices and other sources of funding. Inflation and any governmental response thereto, such as the imposition of higher interest rates or wage controls, our inability to manage costs, or our inability to secure equipment, materials, skilled labour or third-party services necessary to our business activities for the expected price, on the expected timeline, or at all, could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Technology, Information Systems and Data Privacy

We rely heavily on technology, including operations technology and information technology, to effectively run our business. This includes all core technology assets and services, both on-premises and third-party systems, such as networks, computer hardware and software, telecommunications, mobile applications, cloud services and other technologies, including artificial intelligence ("AI"). The organization is introducing AI through a deliberate, strategically governed approach, beginning with pilot-phase use cases that focus on improving productivity and enhancing decision-support capabilities. If we cannot access, use, secure, upgrade or maintain these systems and services or if our information is lost, corrupted or disclosed, operations could be disrupted.

In the ordinary course of business, we collect, use and store sensitive business data, including intellectual property, proprietary information and personal information. Despite security measures, our systems and services may be exposed to risks such as cyber-attacks, espionage, activism, terrorism, war or geopolitical instability, natural disasters, or human errors or malfeasance. Additional risks also include cyber fraud through attacks that bypass controls, impersonate staff or business partners to divert payments or financial assets, or use ransomware to demand payment or block systems access.

Any incident, breach, or disruption of our internal or third-party technology systems or services, including where a threat actor bypasses our cybersecurity measures or business process controls, could result in theft, loss or misuse of internal, confidential, business, financial, proprietary, personal or other sensitive data.

Cyber incidents, privacy or security breaches, or misuse of technology or data (including those involving AI), could also result in business interruption, financial loss, remediation and recovery costs, legal claims or proceedings, liability under law or regulations (including those related to AI, cybersecurity, data processing, or privacy), regulatory penalties or fines (where applicable), operational disruption, reputational damage and other material adverse effects on our business.

The regulatory landscape governing technology use is constantly evolving across all jurisdictions where we operate, covering data processing and transfers, cybersecurity and data protection, third-party risk, AI and privacy. The rapid growth of generative AI tools and embedded features increases technology and data privacy risks through potential misuse, biased or incorrect automated decision-making, or unauthorized exposure of Cenovus's sensitive data.

Failure to comply with laws or regulatory standards, including the use or misuse of AI or inadequate protection of personal data, could result in legal action against the Company by governmental entities or others, fines and penalties (where authorized under relevant law), reputational harm, or may have a negative impact on our financial performance. Compliance with continuously evolving legislation may also increase our operating costs.

Competition

We compete with other producers, refiners and marketers in all aspects, including access to capital, the exploration and development of new and existing sources of supply, the acquisition of crude oil and natural gas interests, and the refining, distribution and marketing of oil and gas products. Resource inventory quality, operating and, or, capital costs, and market access are the primary controllable drivers of financial performance in the energy industry. Cenovus invests in technology innovation and continuous improvement in an effort to reduce costs and improve financial returns to maintain a competitive position relative to peers. The broader hydrocarbon industry also competes with alternative energy sources including renewable fuels and electricity, which compete for market share. Failure to maintain a competitive position relative to hydrocarbon industry peers and alternative energy sources could result in adverse effects to our business, financial condition, cash flows and reputation.

Project Execution

We manage a variety of growth and optimization projects across our global portfolio of assets. In addition, we have other projects in various stages of planning and development, including maintenance and turnaround projects, and projects related to our GHG emissions reduction goals. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of our projects. These risks include, but are not limited to: our ability to obtain the necessary environmental and regulatory approvals; our ability to obtain favourable contract terms or to be granted access within land-use agreements; our ability to access, implement and use operational and information technologies and data, including improvements thereto; risks relating to schedule, contractor performance, engineering and design, transportation and installation of project components, resources and costs, including the availability and cost of materials, equipment and qualified personnel; the impact of supply chain disruptions; the impact of general economic, business and market conditions including inflationary pressures; the impact of weather conditions; risk related to the accuracy of project cost estimates; our ability to finance capital expenditures and expenses on a cost effective basis; our ability to identify or complete strategic transactions; and the effect of changing government laws and regulations, including as a result of new or existing administrations in the jurisdictions in which we conduct operations, development or exploration; and public expectations in relation to the impacts of oil and gas operations on the environment and those associated with GHG emissions abatement initiatives. The commissioning and integration of new infrastructure and facilities within our existing asset base could cause delays in achieving performance targets and objectives. Failure to manage these risks could affect our safety and environmental record and have a material adverse effect on our financial condition, results of operations, cash flows and reputation.

Joint Ventures and Partnerships

Some of our assets are not operated or controlled by us or are held in partnership with others, including through joint ventures and we are, at times, dependent upon our partners for the successful execution and operation of various projects and assets, their management of operational issues and their reporting. In addition, certain of our projects under development, including those related to our GHG emissions reduction goals, are expected to be constructed and operated in collaboration with third parties. Therefore, our results of operations, cash flows and progress towards our GHG emissions reduction goals may be affected by the actions of third-party operators or partners in areas where our ability to control and manage risks may be reduced.

Our partners may have objectives and interests that may not align with, or may conflict with, our interests. No assurance can be provided that our future demands or expectations relating to such assets and projects will be satisfactorily met in a timely manner or at all. If a dispute with a partner or partners were to occur over the development and operation of a project, or if a partner or partners were unable to fund their contractual share of the expenditures, a project could be delayed, and we could be partially or totally liable for our partner's or partners' share of the project. Should one of our partners become insolvent, we may similarly be directed by applicable regulators to carry out obligations on behalf of our partner or partners and may not be able to obtain reimbursement for these costs. Failure to manage these partner risks could have a material adverse effect on our business, financial condition, results of operations, progress towards our GHG emissions reduction goals, reputation and cash flows.

Existing and Emerging Technologies

We depend on, among other things, the availability and scalability of existing and emerging technologies to meet our business goals, including our sustainability goals. Limitations related to the development, adoption and success of these technologies or limited development of disruptive technologies could have a negative impact on our long-term business resilience.

Governmental Policy

Shifts in governmental policy by new or existing administrations can impact our operations and ability to grow our business. Restrictions on fossil fuel-based energy use and cross-border economic activity can impact supply of, demand for, and pricing of our products and services, and our opportunities for continued growth.

Cenovus works with all levels of government in the jurisdictions in which we conduct business operations, development or exploration to ensure we remain competitive, risks are understood and mitigation strategies are implemented; however, we cannot predict the timelines for, and precise effects of, changes in governmental policy which may adversely affect our business, results of operations, financial condition or reputation.

Regulatory Risk

The crude oil, natural gas, NGLs and refining industries in general, and our operations in particular, are subject to regulation and intervention under various levels of legislation in the countries in which we operate, seek to explore, develop and produce crude oil, refined products, natural gas, NGLs and other related products. Regulated areas of our operations include, but are not limited to: land tenure; permitting of projects; royalties; taxes (including income taxes and tariffs); government fees; production rates; environmental protection; occupational and process safety management; protection of certain species or lands; cumulative effects and/or impacts from all types of industrial development; environmental plans, laws and regulations; the reduction of GHG and other emissions; the export and import of crude oil, refined products, natural gas, NGLs and other related products; the transportation of crude oil, refined products, natural gas, NGLs and other related products by pipeline, rail, marine or truck transport; generation, handling, storage, transportation, treatment and disposal of hazardous substances; the awarding, acquisition and maintenance of exploration, development and production rights; the imposition of specific drilling obligations; control over the development, abandonment, remediation and reclamation of fields (including restrictions on production) and/or facilities; and possible expropriation or cancellation of contract rights. See "Environmental Plans and Regulations Risks" below. Any changes to applicable regulatory regimes, including the implementation of new laws or regulations or enforcement initiatives, repeal of any existing laws or regulations, or the modification or changed interpretation of existing laws or regulations, could impact our existing and planned projects requiring increased capital investment, operating expenses or compliance costs, which could adversely impact our financial condition, results of operations, cash flows and reputation.

Regulatory Approvals

Our operations require us to obtain approvals from various regulatory authorities and there are no guarantees that we will be able to obtain and maintain on acceptable conditions, or at all, all necessary licences, permits and other approvals required to conduct activities (including, without limitation, certain exploration, development and operating activities) related to our projects. In addition, obtaining certain approvals from regulatory authorities can involve, among other things, stakeholder consultation, Indigenous consultation (including consensus seeking, collaboration or consent), environmental impact assessments and public hearings. Regulatory approvals obtained may be subject to the satisfaction of certain conditions including, but not limited to: security deposit obligations; ongoing regulatory oversight of projects; mitigating or avoiding project impacts; environmental and habitat assessments; and other commitments or obligations. The failure to obtain applicable regulatory approvals or satisfy any conditions on a timely basis or satisfactory terms could result in increased costs, project delays and may limit Cenovus's ability to develop or expand proposed projects efficiently or at all.

Decommissioning

We are subject to decommissioning, abandonment, remediation and reclamation ("Decommissioning") liabilities for our operations and development and exploration activities, including those imposed by regulation under various levels of legislation in the jurisdictions in which we conduct operations, development or exploration.

We maintain estimates of our Decommissioning liabilities; however, it is possible that these costs may change materially before Decommissioning due to regulatory and legislation changes, technological changes, ecological risks, changes to Decommissioning timelines and inflation, among other variables.

We have an ongoing environmental monitoring program of owned and leased retail locations, and former owned or leased retail locations where we have retained environmental liability and perform remediation where required to comply with contractual and legal obligations. The costs of such remediation may not be determinable due to the unknown timing and extent of corrective actions that may be required.

The impact on our business of any legislative, regulatory or policy decisions relating to the Decommissioning liability regulatory regimes in the jurisdictions in which we conduct operations, development or exploration cannot be reliably or accurately estimated and may be affected by changes in governmental policy, including as a result of new or existing administrations in the jurisdictions in which we conduct operations, development or exploration. Any cost recovery or other measures taken by applicable regulatory bodies may impact Cenovus and could materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

Royalty Regimes

Our cash flows may be directly affected by changes to royalty and mineral tax regimes. The governments of the jurisdictions where we have producing assets receive royalties on the production of hydrocarbons from lands in which they respectively own the mineral rights and which we produce under agreement with each respective government. Government regulation of royalties and mineral tax is subject to change for a number of reasons, including, among other things, political factors. In Canada, there are certain provincial mineral taxes payable on hydrocarbon production from lands other than Crown lands. The potential for changes in the royalty and mineral tax regimes applicable in the jurisdictions in which we conduct operations, development or exploration, or changes to how existing royalty and mineral tax regimes are interpreted and applied by the applicable governments, creates uncertainty relating to the ability to accurately estimate future royalty rates or mineral taxes and could have a significant impact on our business, financial condition, results of operations and cash flows. An increase in the royalty rates or mineral taxes in jurisdictions where we have producing assets would reduce our earnings and could make, in the respective jurisdiction, future capital expenditures or existing operations uneconomic and may reduce the value of our associated assets.

Indigenous Land and Rights Claims

In Canada, Aboriginal and/or treaty rights held by Indigenous peoples are protected under the Constitution. Impacts to these Aboriginal and/or treaty rights must be considered in areas where Cenovus operates. The successful assertion of Indigenous title or other Indigenous rights claims on lands where we operate could have a material adverse impact on our operations or pace of growth.

Opposition by Indigenous communities to our Company, operations, activities, development or exploration on Crown land leases, may adversely impact our reputation and our ability to execute operational or exploration plans. Other impacts may include diversion of Management's time and resources, increased legal, regulatory and other advisory expenses, and impeding our ability to explore, develop and continue to operate projects. In addition, changes in law related to Indigenous rights and title may have a material adverse impact on our business and operations.

Furthermore, Indigenous title or other Indigenous rights claims, as well as opposition by Indigenous communities, can affect the oil and gas and refining industries as a whole. Legal challenges or opposition to major infrastructure projects such as pipelines, railways, or export terminals may result in delays, cancellations, or increased costs. These outcomes may adversely impact our operations, pace of growth, share price and development plans, even if our Company is not directly involved in the development or operation of such projects.

Climate Change-Related Risks

There is international concern regarding climate change and a significant focus on the timing and pace of the transition to a lower-carbon economy. Governments, financial institutions, insurance companies, non-governmental organizations ("NGOs"), environmental and governance organizations, rating agencies, institutional investors, social and environmental activists, shareholders and individuals are seeking to implement, among other things, regulatory and policy changes, changes in investment patterns, and modifications in energy consumption habits and trends which, individually and collectively, are intended to, or have the effect of, accelerating the reduction in the global consumption of fossil fuel-based energy, the conversion of energy usage to less carbon-intensive forms and the general migration of energy usage away from fossil fuel-based forms of energy. A transition to a lower carbon economy could increase the demand for lower emissions and alternative energy sources. Changes in customer behaviour related to reduced energy consumption could impact Cenovus's customers and in turn, the demand for Cenovus's products. Transition to a lower carbon economy could also pose a risk to Cenovus if it is unable to diversify its operations on pace with such a transition.

In addition, climate change-related regulatory, climatic and transition risks can also have industry-wide effects, particularly through their influence on major infrastructure projects. Regulatory changes, market trends, or policy shifts may lead to delays, cancellations, or increased costs for projects critical to the industry. Such impacts may indirectly affect our operations, growth prospects, share price and development plans, even if our Company is not directly involved in the development or operation of such projects.

Climate change and its associated impacts may increase our exposure to, and magnitude of, each of the risks identified in the Risk Management and Risk Factors section of this MD&A. Overall, we are not able to estimate at this time the degree to which climate change-related regulatory, climatic conditions and climate-related transition risks could impact our business, financial condition and results of operations. Our business, financial condition, results of operations, cash flows, reputation, regulatory approvals, access to capital and insurance, cost of borrowing, ability to fund dividend payments and/or business plans may, in particular, without limitation, be adversely impacted as a result of climate change and its associated impacts.

Climate Change Regulations

Cenovus operates in several jurisdictions that regulate, or have proposed to regulate, GHG emissions, often with a view to transitioning to a lower-carbon economy. Some of these regulations are in effect, while others remain in various phases of discussion, review, or implementation, creating policy uncertainty. Further ambiguity exists as a result of the timing and possible impact of any contemplated or emerging regulations, including, but not limited to, how new and existing regulations may be harmonized and synchronized with already existing or contemplated requirements across jurisdictions. Furthermore, policy uncertainty exists as a result of changing government administrations, making the policy and cost impact to the business uncertain and unpredictable. Additional climate change regulations, including the implementation of regulations not currently contemplated, and changes to existing and future regulations, may adversely affect Cenovus's business, financial condition, results of operations, regulatory approvals and cash flows, which impacts cannot be reliably or accurately estimated. Examples of such regulatory change include, but are not limited to, carbon pricing, regulation or limiting of GHG emissions, standards for carbon intensity of liquid fossil fuels, renewable fuel standards, vehicle emissions standards, sales targets for electric vehicles and regulation of electricity generation.

Changes in environmental and emissions legislation and regulations by government authorities could require changes to facility design and operations, potentially increasing the cost of construction, operation and abandonment. Other possible effects from emerging regulations may include, but are not limited to, increased compliance costs, penalties, permitting delays, a general shift away from fossil fuel-based energy, reduced future demand (and corresponding price levels) for our products, substantial costs to generate or purchase emission credits or allowances and higher prices for essential inputs (such as condensate), any of which may increase operating expenses. Further, emission allowances or offset credits may not be available for acquisition or may not be an economically viable option; required emissions reductions may not be technically or economically feasible to implement, in whole or in part; and failure to access resources or technology to meet emissions reduction requirements or other compliance mechanisms may have a material adverse effect to the business, resulting in, among other things, fines, permitting delays, penalties, shutting in production, and/or the suspension of operations.

The extent and magnitude of any adverse impacts of current or future regulations cannot be reliably or accurately estimated, in part because certain legislative and regulatory requirements have not been finalized, others are subject to change, and uncertainty exists with respect to additional measures being considered, the timeframes for compliance and that actual costs and impacts may be different than anticipated and such differences may be material.

Labour Relations

We depend on unionized labour for the operation of certain facilities and may be subject to employee relations and labour disputes, which could disrupt operations at such facilities. As of December 31, 2025, approximately 11 percent of our employees were represented by unions under collective bargaining agreements, which includes approximately 47 percent of our U.S. and one percent of our Canadian workforce.

At unionized worksites there is risk that strikes, or work stoppages could occur, which may have a material adverse effect on our business. The Company may also incur significant costs associated with mitigation and emergency operations plans to ensure continuity of operations in the event of a strike or lockout. Future unionization efforts of Cenovus's non-represented workforce may result in higher wage, benefits and other adverse employment consequences related to flexibility and management rights.

Lastly, we did see increased unionization activity in 2025, which resulted in the unionization of an asset in our Atlantic Region which was previously unrepresented. Changes to the workplace resulting from transactions may increase unionization drive.

2026 will be a busy negotiating period across the organization, as all current collective agreements will expire and are open for renegotiation. Renegotiations of our existing collective bargaining agreements may result in terms that are more or less favourable to us.

Any of these actions may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

Leadership and Talent

Our success depends on strong leadership and a highly skilled, capable workforce. If we are unable to attract, develop and retain key personnel and diverse critical talent with the behaviours, leadership experience, technical and professional competencies needed to support our desired organizational and safety culture, we may face material adverse impacts to our business, safety, reputation, financial condition, results of operations and cash flows. Inadequate management of human-resources–related risks could also result in financial and/or reputational losses or risks, including those arising from actions that do not comply with applicable employment laws.

Additionally, insufficient succession planning or gaps in our talent pipeline for leadership positions could disrupt operations and slow organizational progress.

The integration of new personnel acquired in transactions may result in increased attrition rates in the workforce (including the loss of key employees), disruption of ongoing employment relationships and increased employment-related litigation.

Lastly, failure to sustain a culture that supports safety, inclusion and strong performance may undermine our strategic execution.

Security and Terrorist Threats

Security threats and terrorist activities may impact our personnel, or those of partners, customers and suppliers, which could result in injury, loss of life, extortion, hostage situations and/or kidnapping or unlawful confinement, destruction or damage to property of Cenovus or others, impact to the environment and business interruption. A security threat or terrorist attack targeted at a facility, terminal, pipeline, rail or trucking network, office or offshore vessel/installation owned or operated by Cenovus or any of our systems, services, infrastructure, market access routes, or partnerships could result in the interruption or cessation of key elements of our operations. The risk profile for security and terrorist threats may vary based on geography, international developments and geopolitical risk levels, and the outcomes of such incidents could have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

International Developments and Geopolitical Risk

We are exposed to the financial and operational risks associated with operating in the Asia Pacific region. Our business includes both operated and non-operated assets in the South China Sea and requires cooperation agreements with our partner, China National Offshore Oil Corporation or its subsidiaries (collectively, "CNOOC"). Additionally, the Asia Pacific business includes non-operated assets offshore in the Indonesia Madura Strait, held through and operated by the joint venture, HCML with delegation to CNOOC.

Developments impacting international trade, particularly between Canada and the U.S., the U.S. and China, Canada and China, and the EU and China, including military exercises, changes in laws or enforcement of existing laws, exchange rate fluctuations, trade disputes, the renegotiation or nullification of agreements or treaties, new or increased tariffs and responses thereto (including by governments, our trade partners and customers), which may include, without limitation, retaliatory tariffs, surtaxes, countermeasures, countervailing duties, antidumping duties, export or import taxes on Cenovus's products, and restrictions on imports and exports, such as export controls, sanctions and other measures, may negatively impact development projects, markets and cause weaker macroeconomic conditions or drive political or national sentiment, weakening demand for crude oil, refined products, natural gas, NGLs and other related products, which could materially and adversely affect, among other things, our business, financial condition, results of operations and cash flows.

We may be affected by changes to bilateral relationships, the frameworks and global norms that govern international trade and other geopolitical developments. This includes acute shocks (such as civil unrest or sanctions) and chronic stresses (such as political or business disputes, and other forms of conflict, including military conflict) that may pose longer-term threats to our business. Unilateral action by, or changes in relations between, countries in which we operate, including the U.S. and China, and such countries' approaches to multilateralism and trade protectionism can impact our ability to access markets, technology, talent and capital. Similarly, political developments such as we are currently seeing in Venezuela may lead to short- or longer-term impacts in regional and global oil and gas markets. Disruptions or unanticipated changes of this nature may affect our ability to sell our products for optimum value or access inputs required for effective operations and have the potential to adversely affect our financial condition.

Litigation and Claims

From time-to-time, we may receive demands, or be involved in disputes, regulatory orders, investigations, proceedings, arbitrations and/or litigation ("Claims") arising out of, or related to, our business, operations and/or contractual relationships. Due to the nature of our business and operations, we may be subject to various types of Claims including, but not limited to, failure to comply with applicable laws and regulations such as those related to health and safety, climate change, competition, public statements and marketing, the environment, breach of contract, negligence, product liability, antitrust, bribery and other forms of corruption, tax, securities class actions, derivative actions, patent infringement, privacy, employment, human rights, labour relations, personal injury and other Claims, any of which may be material.

In recent years there has been an increase in climate change-related demands, disputes and litigation in various jurisdictions including the U.S. and Canada and investigations into how climate-related goals are established and promoted. While many of the climate change-related actions are in preliminary stages of litigation, and in some cases assert novel or untested causes of action, there can be no assurance that legal, societal, scientific and political developments will not increase the likelihood of successful climate change-related litigation against energy producers, like Cenovus. We may be subject to adverse publicity associated with such matters, which may negatively affect public perception and our reputation, regardless of whether we are found responsible.

We may be required to incur substantial expenses and devote significant resources in respect of any such Claims. In addition, any such Claims could result in unfavourable judgments, orders, decisions, fines, sanctions, penalties, monetary damages, temporary or permanent suspensions of operations or restrictions on our business. The outcome of any such Claims can be difficult to assess or quantify and may have a material adverse effect on our business, safety, reputation, financial condition, results of operations and cash flows.

Environmental Plans and Regulations Risks

All phases of our operations are subject to environmental plans and regulation, oversight and enforcement pursuant to a variety of laws and regulations imposed by various levels of governments in the jurisdictions in which we conduct operations, development or exploration, including land management plans, laws and regulations. Compliance with applicable regulations may result in approval delays for projects, critical licences and permits, stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, litigation, increased capital and operating expenses, increased compliance costs and increased costs for closure, controls/limits on land and resource access, reclamation, and ecological restoration. Third-party NGOs, citizen activist groups and Indigenous communities can also influence environmental laws and regulations in the jurisdictions in which we conduct our operations, development or exploration, including the U.S. and Canada. We anticipate that further changes in environmental laws and regulations will occur. The complexities of changes in environmental laws and regulations make it difficult to predict the potential future impact to our business.

U.S. environmental and health and safety regulations and their aggressive enforcement from regulators present challenges and risks to our U.S. operations. These risks can arise if new emissions standards, water quality standards, occupational or process safety management requirements, or regulation of emerging contaminants are finalized or the government develops new interpretations that can increase compliance costs, require capital projects, lengthen project implementation times, and have an adverse effect on our business, financial condition, results of operations and cash flows.

Canadian Species at Risk Act

The Canadian federal Species at Risk Act ("SARA") and associated agreements, as well as provincial regulation regarding threatened or endangered species and their habitat, may limit the pace and the amount of development or activity in areas identified as critical habitat for species of concern. The extent and magnitude of any potential adverse impacts of legislation on project development and operations are difficult to predict, as uncertainty exists as to whether jurisdictional plans and actions undertaken will be sufficiently stringent to satisfy the SARA and associated provisions. Similarly, uncertainty exists with respect to the outcome of litigation that could be initiated with respect to federal duties and obligations pursuant to the SARA.

Canadian Federal Air Quality Management System

The Multi-Sector Air Pollutants Regulations ("MSAPR"), under the Canadian Environmental Protection Act, 1999, set mandatory national air pollutant emission standards to protect the environment and health of Canadians. It established nitrogen oxides emission limits for specific equipment, including stationary engines, boilers and heaters, across several industrial sectors. We anticipate that the MSAPRs will result in adverse impacts to Cenovus, including, but not limited to, capital investment required to retrofit existing equipment and increased operating costs.

Canadian Ambient Air Quality Standards ("CAAQS") for nitrogen dioxide, sulphur dioxide, fine particulate matter and ozone were introduced as part of a national Air Quality Management System. Provinces may implement the CAAQS at the regional air zone level and air zone management actions may include more stringent emissions standards applicable to industrial sources from approval holders in regions where we operate that may result in adverse impacts including, but not limited to, capital investment to retrofit existing facilities and increased operating costs.

Review of Environmental and Regulatory Processes

Increased or evolving environmental assessment obligations imposed by various levels of governments in the jurisdictions in which we conduct operations, development or exploration may create risk of increased costs, project development delays and an increased number of conditions. The regulatory frameworks within the jurisdictions where we conduct operations, development or exploration are constantly evolving and may become more onerous or costly, which may impede our ability to economically develop our resources. The extent and magnitude of any adverse impacts of changes to such regulatory frameworks on project development and operations cannot be estimated at this time.

Water Regulation

We utilize fresh water in certain operations, which is obtained in accordance with respective jurisdictions' regulations, including through water licences. If water fees increase, the terms of water licences change or there are restrictions in the amount of water available for our use, production could decline or operating expenses could increase, both of which may have a material adverse effect on our business and financial condition. There can be no assurance that current or future water licences will be continued or approved. This may adversely affect our business, including the ability to operate our assets and execute development plans.

Our U.S. refineries are subject to water discharge requirements that necessitate treatment of wastewater prior to discharging. Non-compliance with these requirements can lead to enforcement actions by regulators, including issuance of fines, orders to upgrade treatment plants and suspension of operations. Federal and state regulators in the U.S. are currently addressing per- and polyfluoroalkyl substances ("PFAS") in water discharge permits by requiring installation of additional wastewater treatment units and requiring monitoring of PFAS in discharges.

Hydraulic Fracturing

Legislative and regulatory initiatives have been introduced related to stakeholder claims that hydraulic fracturing techniques are harmful to surface water and drinking water sources and are increasing the frequency of seismic activity. New laws, regulations or permitting requirements regarding hydraulic fracturing may lead to limitations or restrictions to oil and gas development activities, operational delays, increased compliance costs, restrictions to freshwater usage, additional operating requirements or increased third-party or governmental claims, resulting in increased cost of doing business, as well as impacting the amount of natural gas and oil that we are ultimately able to produce from our reserves.

Sustainability Focus Areas and Goals

We have established meaningful goals in our sustainability focus areas and continue to allocate resources and progress tangible plans to meet these ambitions. To achieve these goals and to respond to changing market demand, we may incur additional costs and invest in innovation. It is possible that the benefits of these investments may be less than we expect, which may have an adverse effect on our business, financial condition and reputation.

Generally, our sustainability goals depend on our ability to execute our current business strategy, which can be impacted by the numerous risks and uncertainties associated with our business and the industry in which we operate, as outlined in the Risk Management and Risk Factors section of this MD&A. Investors and stakeholders may compare companies based on sustainability-related performance, including climate-related performance. Failure to achieve our sustainability goals, or a perception among key stakeholders that our sustainability goals are insufficient or unattainable, could adversely affect our reputation and our ability to attract capital and insurance coverage, and could result in claims that we misrepresented our goals or our ability to achieve them.

There is also a risk that some or all of the expected benefits and opportunities of achieving the various sustainability goals may fail to materialize, may cost more to achieve than we expect or may not occur within the anticipated time periods or at all. In addition, there is a risk that the actions we take in implementing ambitions relating to our sustainability focus areas may, among other things, increase our capital expenditures and thereby impair our ability to invest in other aspects of our business, which could have a negative impact on our future operating and financial results.

Climate and GHG Emissions Reduction Goals

Our ability to meet our GHG emissions reduction goals is subject to numerous risks and uncertainties and our actions taken in implementing such goals may also expose us to certain additional and/or heightened litigation, financial and operational risks. A reduction in GHG emissions relies on, among other things, our ability to develop, access and implement commercially viable and scalable emissions reduction strategies, and related technology and products. If we are unable to implement these strategies and technologies as planned without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, we may be unable to meet our GHG emissions reduction goals on the planned timeline, or at all. In those circumstances, this could result in claims that we misrepresented our goals or our ability to achieve them.

Furthermore, longer-term goals are inherently less certain due to the longer timeframe and certain factors outside of our control, including the commercial application of future technologies that may be necessary for us to achieve such goals, and the cooperation and actions of third parties, including Pathways Alliance. The Pathways Alliance's proposed carbon capture and storage project is of particular relevance, and if this project is delayed or does not proceed, Cenovus's ability to achieve its GHG reduction goals and ambitions will be delayed and may not be achieved.

In addition, achieving our GHG emissions reduction goals relies on the existence of a favourable and stable regulatory framework that includes, among other things, support from various levels of government, including financial support and shared capital cost commitments, which may not develop in a manner consistent with our expectations, or at all. Achieving our GHG emissions reduction goals will also require capital expenditures and Company resources, with the potential that actual costs may differ from our original estimates and the differences may be material. Furthermore, the cost of investing in emissions-reduction technologies, and the resulting change in the deployment of resources and focus, could have a negative impact on our business, financial condition, results of operations and cash flows.

Water Stewardship Goals

Our ability to meet our water stewardship goals will depend on the commercial viability and scalability of relevant water reduction strategies, and related steam and water usage technology and products. There are risks associated with relying largely or partly on new technologies, the incorporation of such technologies into new or existing operations and acceptance of new technologies in the market. In the event we are unable to effectively deploy the necessary strategies and technologies as planned, without negatively impacting our expected operations or cost structure, or such strategies or technologies do not perform as expected, progress toward our goals could be interrupted, delayed or abandoned. In those circumstances, this could result in claims that we misrepresented our goals or our ability to achieve them.

Biodiversity Goals

Our ability to meet our biodiversity ambitions is subject to various operational, environmental and regulatory risks, which could impose significant costs, restrictions, liabilities and obligations on us. See "Decommissioning" above. In addition, an increase in operating costs, changes to market conditions and access to additional capital, if needed, could result in our inability to fund, and meet, our biodiversity goals on the current timelines, or at all. In some cases, meeting our biodiversity ambitions has operational implications for reduced operational footprint and accelerated abandonment, reclamation and restoration. In the event that we do not meet our goals, this could result in claims that we misrepresented our goals or our ability to achieve them.

Indigenous Reconciliation Goals

A failure or delay in achieving our Indigenous reconciliation ambitions or continuing to advance Indigenous reconciliation initiatives may adversely affect our relationship with neighbouring Indigenous businesses and communities, and our reputation.

Acceptance and Belonging Goals

The acceptance and belonging of our staff plays a critical role in strengthening our business performance and culture. A failure or delay in achieving our acceptance and belonging ambitions could have a material adverse effect on our recruitment activities, retention efforts and reputation with our stakeholders.

Reputation Risk

We rely on our reputation to build and maintain positive relationships with investors and other stakeholders, to recruit and retain staff and to be viewed as a credible, trusted company. All of our actions can influence public or key stakeholder opinions and decisions, which may adversely affect our share price, development plans or ability to continue operations.

Development of fossil fuel-based energy, and oil sands in particular, has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous reconciliation. Concerns about oil sands may, directly or indirectly, impair the profitability of our current oil sands projects and the viability of future oil sands projects by creating significant regulatory, economic and operating uncertainty, and could lead to constrained access to insurance, liquidity and capital, and affect demand for our products.

Shareholder activism has been increasing in the oil and gas industry, and investors may from time-to-time attempt to effect changes to our business, governance or reporting practices with respect to climate change or otherwise, whether by shareholder proposals, public campaigns, proxy solicitations or otherwise. Such actions, successful or not, could adversely impact our business by distracting from core business operations, incurring increased advisory fees and related costs, interfering with our ability to successfully execute on strategic transactions and plans, affecting our ability to attract and retain staff, creating significant fluctuation in our share price, and provoking perceived uncertainty about the future direction of our business.

Internet search functions are increasingly using AI to summarize search results, often sourcing information from sites containing misinformation or inaccuracies. Investors and other stakeholders seeking information about Cenovus may be directed to falsehoods or incomplete information about the company, potentially impacting perceptions and decisions about our business or operations and incurring staff time to mitigate.

Other Risks

Dilutive Effect

We are authorized to issue, among other classes of shares, an unlimited number of common shares for consideration and on terms and conditions as established by our Board, without the approval of our shareholders in certain instances. Any future issuances of Cenovus common shares or other securities exercisable or convertible into, or exchangeable for, Cenovus common shares may result in dilution to present and prospective Cenovus shareholders. The issuance of additional Cenovus common shares upon exercise, from time-to-time, of securities convertible into Cenovus common shares, including equity awards granted to our directors and officers, will have a further dilutive effect on the ownership interest of shareholders of Cenovus. Such dilutive effect on Cenovus's earnings per share could adversely affect the market price of Cenovus common shares and the value of our shareholders' investments.

Risks Relating to Acquisitions and Divestitures

We have completed, and may complete in the future, acquisitions and divestitures for various strategic reasons. We may not be able to complete such transactions on favourable terms, on a timely basis, or at all. The integration of acquired assets and operations may result in the disruption of business and may divert Management’s focus and resources from other strategic opportunities and operational matters during the process. This may result in increased costs and could adversely affect our ability to achieve the anticipated benefits of such transactions, as well as other strategic opportunities or operational matters. Acquiring assets requires assessments of their characteristics which are inexact and inherently uncertain and, as such, the acquired assets may not produce or operate as expected, may not have the anticipated benefits or synergies and may be subject to increased costs and liabilities. Further, we may not be able to obtain or realize upon contractual indemnities from a seller for liabilities created prior to an acquisition.

Various factors could materially affect our ability to dispose of assets in the future and may also reduce the proceeds or value realized from such divestitures. We may also retain certain liabilities or agree to indemnification obligations in a sale transaction, which may be difficult to quantify at the time of the transaction and could be material.

Should any of the risks associated with acquisitions or divestitures materialize, they could have an adverse effect on our business, financial condition or reputation.

Risks Related to Significant Shareholders of Cenovus

The sale into the market of Cenovus common shares held by significant shareholders of Cenovus, Hutchison Whampoa Europe Investments S.à r.l. ("Hutchison") and L.F. Investments S.à r.l. ("L.F. Investments", together with Hutchison, the "Significant Shareholders") or market perception regarding any intention of the Significant Shareholders to sell Cenovus common shares, could adversely affect market prices for our common shares. In addition, the Significant Shareholders may be able to impact certain matters requiring Cenovus shareholder approval. While the Significant Shareholders were subject to certain voting and selling restrictions pursuant to standstill agreements each shareholder entered into with Cenovus, such agreements expired on January 1, 2026.

Income and Property Tax Laws

Our operations are subject to complex and continually evolving tax laws and regulations in multiple jurisdictions. Evolving jurisprudence and changes in legislation, regulations or governmental policy could adversely affect our financial results and ability to achieve strategic objectives. Tax authorities may challenge our filings, and audits or disputes could result in additional liabilities.

Pandemic Risk

Pandemics, epidemics or outbreaks constitute ongoing risks to the Company, with their ultimate impacts remaining uncertain and subject to change. Such events, along with any measures implemented by Cenovus or governmental authorities to protect the health and safety of personnel and ensure business continuity, may give rise to legal disputes, diminished demand and pricing for key commodities, and could adversely affect the Company's business performance, financial condition and reputation.

Fighting Against Forced Labour and Child Labour in Supply Chains Act

The *Fighting Against Forced Labour and Child Labour in Supply Chains Act* requires Cenovus to publish an annual report on steps taken to assess and mitigate the risk of forced or child labour in its business and supply chains. Canadian customs regulations also prohibit importing goods produced with forced, child and prison labour, as well as the possession, purchase, sale, exchange, acquisition or disposition of these goods after they have been imported. Heightened regulatory scrutiny and evolving legislation, and our response to these changes, may disrupt our supply chains, affecting availability or cost of goods and materials, procurement processes, productivity, operating costs and financial condition. There is a risk that our supply chain may use or be alleged to use forced or child labour and gathering sufficient information from suppliers to assess and mitigate such risks may be challenging. Our due diligence and mitigation activities might not identify or mitigate all risks, exposing Cenovus to reputational harm. The Government of Canada may expand these requirements, but the timing and impact of any such expansion remains uncertain.

A discussion of additional risks, should they arise after the date of this MD&A, which may impact our business, prospects, financial condition, results of operations and cash flows, and in some cases our reputation, can be found in our subsequently filed MD&A, available on SEDAR+ at sedarplus.ca, on EDGAR at sec.gov and at cenovus.com.

CRITICAL ACCOUNTING JUDGMENTS, ESTIMATION UNCERTAINTIES AND ACCOUNTING POLICIES

Management is required to make estimates and assumptions, as well as use judgment, in the application of accounting policies that could have a significant impact on our financial results. Actual results may differ from estimates and those differences may be material. The estimates and assumptions used are subject to updates based on experience and the application of new information. Our material accounting policies are reviewed annually by the Audit Committee of the Board. Further details on the basis of preparation and our material accounting policies can be found in the notes to the Consolidated Financial Statements.

Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in the Company's Consolidated Financial Statements.

Identification of Cash-Generating Units

Cash-generating units ("CGUs") are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and impairment reversals.

Assessment of Impairment Indicators or Impairment Reversals

PP&E, E&E assets and right-of-use assets are reviewed separately for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. The identification of indicators of impairment or reversal of impairment requires significant judgment.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment.

On September 30, 2025, Cenovus divested its entire 50 percent interest in WRB, which was a jointly-controlled entity. The joint arrangement met the definition of a joint operation under IFRS 11, *"Joint Arrangements"* ("IFRS 11"); therefore, the Company recognized its share of the assets, liabilities, revenues and expenses in its consolidated results up to the date of divestiture.

In determining the classification of its joint arrangement under IFRS 11, the Company considered the following:

- The original intention of the joint arrangement was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements required the partners to make contributions if funds were insufficient to meet the obligations or liabilities of the corporation and partnership. The past and future development of WRB was dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB had third-party debt facilities to cover short-term working capital requirements.
- Phillips 66, as operator of WRB, either directly or through wholly-owned subsidiaries, provided marketing services, purchased necessary feedstock, and arranged for transportation and storage, on the partners' behalf as the agreements prohibited the partners from undertaking these roles themselves. In addition, the joint arrangement did not have employees and, as such, was not capable of performing these roles.
- In the arrangement, output was taken by the partners, indicating that the partners had the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangement.

Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis, and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

The evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could change assumptions used to determine the recoverable amount of the Company's PP&E and E&E assets and could affect the carrying value of those assets, may affect future development or viability of exploration prospects, may curtail the expected useful lives of oil and gas assets thereby accelerating depreciation charges and may accelerate decommissioning obligations increasing the present value of the associated provisions. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. Environmental considerations are built into estimates through the use of key assumptions used to estimate fair value including forward commodity prices, forward crack spreads, net of renewable identification numbers. and discount rates. The energy transition could impact the future prices of commodities. Pricing assumptions used in the determination of recoverable amounts incorporate market expectations and the evolving worldwide demand for energy.

The following are the key estimates, assumptions and judgments at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the expected future production volumes, future development and operating expenses, forward commodity prices, estimated royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and DD&A expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its independent qualified reserves evaluators ("IQREs").

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include quantity of reserves, expected future production volumes, future development and operating expenses, forward commodity prices and discount rates. Recoverable amounts for the Company's downstream assets use assumptions such as refined product production, forward crude oil prices, forward crack spreads, net of RINs, future operating expenses, future capital expenditures and discount rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence of liabilities and estimate the future value. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired, liabilities assumed and assets given up in a business combination, including contingent consideration and goodwill, if any, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparable transactions and discounted cash flows. For the Company's upstream assets, key assumptions in the discounted cash flow models used to estimate fair value include forward commodity prices, expected future production volumes, quantity of reserves, discount rates, and future development and operating expenses. Estimated production volumes and quantity of reserves for acquired oil and gas properties were developed by internal geology and engineering professionals, and IQREs. Changes in these variables could significantly impact the carrying value of the net assets acquired.

Income Tax Provisions

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

New Accounting Standards and Interpretations not yet Adopted

Financial Instruments

On May 30, 2024, the IASB issued amendments to IFRS 9, *"Financial Instruments",* and IFRS 7, *"Financial Instruments: Disclosures".* The amendments include clarifications on the derecognition of financial liabilities and the classification of certain financial assets. In addition, new disclosure requirements for equity instruments designated as fair value through other comprehensive income (loss) were added. The amendments are effective for annual periods beginning on or after January 1, 2026, and will be applied retrospectively. The amendments to IFRS 9 and IFRS 7 will not have a material impact on the Consolidated Financial Statements.

Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued IFRS 18, *"Presentation and Disclosure in Financial Statements"* ("IFRS 18"), which will replace International Accounting Standard 1, *"Presentation of Financial Statements"*. IFRS 18 will establish a revised structure for the Consolidated Statements of Comprehensive Income (Loss) and improve comparability across entities and reporting periods.

IFRS 18 is effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The Company is continuing to evaluate the impacts of adopting IFRS 18 on the Consolidated Financial Statements. Cenovus will adopt IFRS 18 effective January 1, 2027, using the retrospective approach.

CONTROL ENVIRONMENT

Management, including our President & Chief Executive Officer and Executive Vice-President & Chief Financial Officer, assessed the design and effectiveness of ICFR and DC&P as at December 31, 2025. In making its assessment, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of ICFR. Based on our evaluation, Management has concluded that both ICFR and DC&P were effective as at December 31, 2025.

On November 13, 2025, Cenovus completed the MEG Acquisition. As permitted by and in accordance with, NI 52-109, and guidance issued by the U.S. Securities and Exchange Commission, Management has limited the scope and design of ICFR and DC&P to exclude the controls, policies and procedures in respect of the business acquired from MEG. Such scope limitation is primarily due to the time required for Management to assess the ICFR and DC&P relating to the business acquired from MEG in a manner consistent with our other operations. Further integration will take place throughout the remainder of 2026 as processes and systems align.

Assets attributable to MEG as at December 31, 2025, represented approximately 18 percent of Cenovus's total assets, and revenues attributable to MEG for the period of November 13, 2025, to December 31, 2025, represented approximately one percent of Cenovus's total revenues for the three months ended December 31, 2025.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

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FOR THE YEAR ENDED DECEMBER 31, 2025

(Canadian dollars)

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REPORT OF MANAGEMENT

Management's Responsibility for the Consolidated Financial Statements

The accompanying Consolidated Financial Statements of Cenovus Energy Inc. are the responsibility of Management. The Consolidated Financial Statements have been prepared by Management in Canadian dollars in accordance with International Financial Reporting Accounting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management's best judgments.

The Board of Directors has approved the information contained in the Consolidated Financial Statements. The Board of Directors fulfills its responsibility regarding the financial statements mainly through its Audit Committee which is made up of five independent directors. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation and the United States Sarbanes – Oxley Act of 2002 and voluntarily complies, in principle, with the Audit Committee guidelines of the New York Stock Exchange. The Audit Committee meets with Management and the independent auditors on at least a quarterly basis to review and recommend the approval of the interim Consolidated Financial Statements and Management's Discussion and Analysis to the Board of Directors prior to their public release, as well as annually to review the annual Consolidated Financial Statements and Management's Discussion and Analysis and recommend their approval to the Board of Directors.

Management's Assessment of Internal Control Over Financial Reporting

Management is also responsible for establishing and maintaining adequate internal control over financial reporting. The internal control system was designed to provide reasonable assurance to Management regarding the preparation and presentation of the Consolidated Financial Statements.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Management has assessed the design and effectiveness of internal control over financial reporting as at December 31, 2025. In making its assessment, Management has used the Committee of Sponsoring Organizations of the Treadway Commission framework in Internal Control – Integrated Framework (2013) to evaluate the design and effectiveness of internal control over financial reporting. Based on their evaluation, Management has concluded that internal control over financial reporting was effective as at December 31, 2025.

Management excluded the internal control activities of the business acquired by the Company through a business combination in 2025 (see Note 4) from its assessment of internal control over financial reporting as at December 31, 2025. The total assets and total revenues of the acquired business excluded from Management's assessment of internal control over financial reporting represents 18 percent and one percent, respectively, of the related Consolidated Financial Statement amounts as at and for the year ended December 31, 2025.

The Consolidated Financial Statements of Cenovus Energy Inc. as at December 31, 2025, and 2024, and for each of the two years in the period ended December 31, 2025, and the effectiveness of internal control over financial reporting as of December 31, 2025, has been audited and unqualified opinions have been issued by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report dated February 18, 2026.

/s/ Jonathan M. McKenzie
Jonathan M. McKenzie
President & Chief Executive Officer
Cenovus Energy Inc.

/s/ Karamjit S. Sandhar
Karamjit S. Sandhar
Executive Vice-President & Chief Financial Officer
Cenovus Energy Inc.

February 18, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of Cenovus Energy Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Cenovus Energy Inc. and its subsidiaries (the Company) as of December 31, 2025 and 2024, and the related consolidated statements of comprehensive income (loss), of equity and of cash flows for the years then ended, 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 the years then ended in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board. 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.

As described in Management's Assessment of Internal Control Over Financial Reporting, management has excluded MEG Energy Corp. from its assessment of internal control over financial reporting as of December 31, 2025, because it was acquired by the Company through a business combination during 2025. We have also excluded MEG Energy Corp. from our audit of internal control over financial reporting. MEG Energy Corp. was a wholly-owned subsidiary whose total assets and total revenues excluded from management's assessment and our audit of internal control over financial reporting represent 18% and 1%, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2025.

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.

Impact of Crude Oil and Natural Gas Reserves (together, the Reserves) on Property, Plant and Equipment, Net (PP&E) within the Oil Sands segment

As described in notes 1, 3, 16 and 35 to the Consolidated Financial Statements, the PP&E balance in the Oil Sands segment was $34.1 billion as of December 31, 2025. In aggregate, the Company recognized $3.4 billion of depreciation, depletion and amortization (DD&A) expense related to the Oil Sands segment for the year ended December 31, 2025. Management calculates depletion for the Oil Sands segment PP&E using the unit-of-production method based on estimated proved reserves. Costs subject to depletion include estimated future development costs to be incurred in developing those proved reserves. Estimating proved reserves requires the use of key assumptions and judgments by Management including expected future production volumes, future development and operating expenses, as well as forward commodity prices. Management's estimates of proved reserves used for the calculation of DD&A expense related to PP&E in the Oil Sands segment have been developed by Management's specialists, specifically independent qualified reserves evaluators.

The principal considerations for our determination that performing procedures relating to the impact of proved reserves on PP&E, within the Oil Sands segment is a critical audit matter are (i) the significant amount of judgment required by Management, including the use of Management's specialists, when developing the estimates of proved reserves; (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating audit evidence obtained related to expected future production volumes, future development and operating expenses, as well as forward commodity prices; and (iii) 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 controls relating to Management's estimates of proved reserves and the calculation of DD&A expenses related to PP&E in the Oil Sands segment. These procedures also included, among others, testing Management's process for determining DD&A expense for the Oil Sands segment, which included for certain properties (i) evaluating the appropriateness of the methods used by Management in making these proved reserve estimates; (ii) testing the completeness and accuracy of the underlying data used in Management's estimates of proved reserves; (iii) assessing the reasonability of the key assumptions related to expected future production volumes, future development and operating expenses, as well as forward commodity prices, and (iv) testing the unit-of-production rates used to calculate DD&A expense. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the estimated proved reserves used in the calculation of DD&A expense related to PP&E in the Oil Sands segment. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included, for certain properties within the Oil Sands segment, evaluation of the methods and key assumptions used by the specialists, tests of data used by the specialists, and an evaluation of the specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable. Evaluating the key assumptions used by Management's specialists related to expected future production volumes, future development and operating expenses, as well as forward commodity prices involved assessing whether the key assumptions used were reasonable considering the current and past performance of the Oil Sands segment and consistency with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable.

Valuation of acquired Property, Plant and Equipment (PP&E) related to the acquisition of MEG Energy Corp.

As described in notes 1, 3, 4 and 35 to the Consolidated Financial Statements, on November 13, 2025, the Company acquired MEG Energy Corp. (MEG) in an acquisition accounted for as a business combination using the acquisition method, which requires that assets acquired and liabilities assumed be measured at fair value on the acquisition date, with any excess of the purchase price over the estimated fair value of the net assets acquired recorded as goodwill. Total consideration for the total issued and outstanding common shares of MEG, including those previously owned by the Company, was $7.9 billion. The assets acquired included PP&E, which was valued at $9.7 billion. Management estimated the fair value of the acquired PP&E at the acquisition date using a discounted cash flow model. This fair value assessment required the use of significant judgments by Management including key assumptions related to forward commodity prices, expected future production volumes, quantity of reserves, future development and operating expenses and discount rate. The quantity of reserves has been developed by Management's specialists, including independent qualified reserve evaluators.

The principal considerations for our determination that performing procedures relating to the valuation of acquired PP&E related to the acquisition of MEG Energy Corp. is a critical audit matter are (i) the significant judgment by Management, including the use of Management’s specialists, as applicable, when developing the fair value of the acquired PP&E; (ii) the high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating key assumptions used in the discounted cash flow model used to value the acquired PP&E related to forward commodity prices, expected future production volumes, quantity of reserves, future development and operating expenses and discount rate; and (iii) 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 controls relating to Management's estimated fair value of the acquired PP&E. These procedures also included, among others, testing Management's process for determining the fair value of the acquired PP&E, which included (i) evaluating the appropriateness of the discounted cash flow model used by Management in making this estimate; (ii) testing the completeness and accuracy of underlying data used in Management's determination of the fair value and (iii) assessing the reasonability of the key assumptions related to forward commodity prices, expected future production volumes, quantity of reserves, future development and operating expenses and discount rate. The work of Management's specialists was used in performing the procedures to evaluate the reasonableness of the quantity of reserves. As a basis for using this work, the specialists' qualifications were understood, and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and key assumptions used by the specialists, tests of the data used by the specialists, and an evaluation of the specialists' findings. Professionals with specialized skill and knowledge assisted in this evaluation, as applicable. Evaluating the key assumptions used by Management's specialists also involved assessing whether the key assumptions used were reasonable considering the current and past performance of MEG and the Company and consistency with industry pricing forecasts and evidence obtained in other areas of the audit, as applicable. Professionals with specialized skill and knowledge were used to assist in evaluating the overall reasonableness of the fair value of the acquired PP&E determined by Management, including the discount rate.

/s/ PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Canada
February 18, 2026
We have served as the Company's auditor since 2008.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31,
($ millions, except per share amounts)

	Notes	**2025**	2024
Revenues	1	**49,696**	54,277
Expenses	1		
Purchased Product, Transportation and Blending		**32,688**	36,641
Operating		**6,336**	6,841
(Gain) Loss on Risk Management	31	**(37)**	58
Depreciation, Depletion, Amortization and Exploration Expense	15,16,17	**5,233**	4,940
(Income) Loss From Equity-Accounted Affiliates	18	**(53)**	(66)
General and Administrative	5	**812**	794
Finance Costs, Net	6	**569**	514
Integration, Transaction and Other Costs	4	**234**	166
Foreign Exchange (Gain) Loss, Net	7	**(361)**	462
(Gain) Loss on Divestiture of Assets	4,8	**(87)**	(119)
Re-measurement of Contingent Payments		**—**	30
Other (Income) Loss, Net		**(115)**	(55)
Earnings (Loss) Before Income Tax		**4,477**	4,071
Income Tax Expense (Recovery)	10	**547**	929
Net Earnings (Loss)		**3,930**	3,142
Other Comprehensive Income (Loss), Net of Tax	27		
Items That Will not be Reclassified to Profit or Loss:			
Actuarial Gain (Loss) Relating to Pension and Other Post-Employment Benefits	25	**17**	14
Change in the Fair Value of Equity Instruments at FVOCI [(1)]	31	**(25)**	71
Items That may be Reclassified to Profit or Loss:			
Foreign Currency Translation Adjustment		**(1,904)**	1,020
Total Other Comprehensive Income (Loss), Net of Tax		**(1,912)**	1,105
Comprehensive Income (Loss)		**2,018**	4,247
Net Earnings (Loss) Per Common Share ($)	11		
Basic		**2.16**	1.68
Diluted		**2.15**	1.67

(1) Fair value through other comprehensive income (loss) ("FVOCI").

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

As at December 31,
($ millions)

	Notes	**2025**	2024
Assets			
Current Assets			
Cash and Cash Equivalents	12	**2,740**	3,093
Accounts Receivable and Accrued Revenues	13	**3,435**	2,614
Income Tax Receivable		**366**	231
Inventories	14	**3,349**	4,496
Total Current Assets		**9,890**	10,434
Restricted Cash	23	**256**	241
Exploration and Evaluation Assets, Net	1,15	**575**	484
Property, Plant and Equipment, Net	1,16	**45,260**	38,568
Right-of-Use Assets, Net	1,17	**2,153**	1,950
Income Tax Receivable		**25**	25
Investments in Equity-Accounted Affiliates	18	**295**	399
Other Assets	19	**464**	451
Deferred Income Taxes	10	**1,594**	1,064
Goodwill	1,20	**2,912**	2,923
Total Assets		**63,424**	56,539
Liabilities and Equity			
Current Liabilities			
Accounts Payable and Accrued Liabilities	21	**5,847**	6,242
Income Tax Payable		**98**	396
Short-Term Borrowings	22	**—**	173
Long-Term Debt	22	**—**	192
Lease Liabilities	17	**369**	359
Total Current Liabilities		**6,314**	7,362
Long-Term Debt	22	**11,032**	7,342
Lease Liabilities	17	**2,806**	2,568
Decommissioning Liabilities	23	**4,872**	4,534
Other Liabilities	24	**889**	919
Deferred Income Taxes	10	**5,873**	4,045
Total Liabilities		**31,786**	26,770
Shareholders' Equity		**31,622**	29,754
Non-Controlling Interest		**16**	15
Total Liabilities and Equity		**63,424**	56,539
Commitments and Contingencies	34		

See accompanying Notes to the Consolidated Financial Statements.

/s/ Alexander J. Pourbaix
Alexander J. Pourbaix
Director
Cenovus Energy Inc.

/s/ Jane E. Kinney
Jane E. Kinney
Director
Cenovus Energy Inc.

February 18, 2026

CONSOLIDATED STATEMENTS OF EQUITY

($ millions)

	Shareholders' Equity							
	Common Shares	Treasury Shares	Preferred Shares	Warrants	Paid in Surplus	Retained Earnings	AOCI [1]	Total
	(Note 26)	(Note 26)	(Note 26)	(Note 26)	(Note 26)		(Note 27)	
As at December 31, 2023	16,031	—	519	25	2,002	8,913	1,208	28,698
Net Earnings (Loss)	—	—	—	—	—	3,142	—	3,142
Other Comprehensive Income (Loss), Net of Tax	—	—	—	—	—	—	1,105	1,105
Total Comprehensive Income (Loss)	—	—	—	—	—	3,142	1,105	4,247
Common Shares Issued Under Stock Option Plans	68	—	—	—	(16)	—	—	52
Purchase of Common Shares Under NCIB [2]	(479)	—	—	—	(966)	—	—	(1,445)
Purchase of Common Shares Under Employee Benefit Plan	—	(43)	—	—	—	—	—	(43)
Preferred Shares Redeemed	—	—	(163)	—	(87)	—	—	(250)
Warrants Exercised	39	—	—	(13)	—	—	—	26
Stock-Based Compensation Expense	—	—	—	—	11	—	—	11
Base Dividends on Common Shares	—	—	—	—	—	(1,255)	—	(1,255)
Variable Dividends on Common Shares	—	—	—	—	—	(251)	—	(251)
Dividends on Preferred Shares	—	—	—	—	—	(36)	—	(36)
As at December 31, 2024	**15,659**	**(43)**	**356**	**12**	**944**	**10,513**	**2,313**	**29,754**
Net Earnings (Loss)	**—**	**—**	**—**	**—**	**—**	**3,930**	**—**	**3,930**
Other Comprehensive Income (Loss), Net of Tax	**—**	**—**	**—**	**—**	**—**	**—**	**(1,912)**	**(1,912)**
Total Comprehensive Income (Loss)	**—**	**—**	**—**	**—**	**—**	**3,930**	**(1,912)**	**2,018**
Common Shares Issued (Note 4)	**3,667**	**—**	**—**	**—**	**—**	**—**	**—**	**3,667**
Common Shares Issued Under Stock Option Plans	**20**	**—**	**—**	**—**	**(4)**	**—**	**—**	**16**
Purchase of Common Shares Under NCIB [2]	**(771)**	**—**	**—**	**—**	**(541)**	**(683)**	**—**	**(1,995)**
Purchase of Common Shares Under Employee Benefit Plan	**—**	**(155)**	**—**	**—**	**—**	**—**	**—**	**(155)**
Common Shares Issued Under Employee Benefit Plan	**—**	**82**	**—**	**—**	**(6)**	**—**	**—**	**76**
Preferred Shares Redeemed	**—**	**—**	**(243)**	**—**	**(107)**	**—**	**—**	**(350)**
Warrants Exercised	**24**	**—**	**—**	**(8)**	**—**	**—**	**—**	**16**
Stock-Based Compensation Expense	**—**	**—**	**—**	**—**	**12**	**—**	**—**	**12**
Base Dividends on Common Shares	**—**	**—**	**—**	**—**	**—**	**(1,423)**	**—**	**(1,423)**
Dividends on Preferred Shares	**—**	**—**	**—**	**—**	**—**	**(14)**	**—**	**(14)**
As at December 31, 2025	**18,599**	**(116)**	**113**	**4**	**298**	**12,323**	**401**	**31,622**

(1) Accumulated other comprehensive income (loss) ("AOCI").
(2) Normal course issuer bid ("NCIB"). Includes taxes payable on purchase of shares.

See accompanying Notes to the Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31,
($ millions)

	Notes	**2025**	2024
Operating Activities			
Net Earnings (Loss)		**3,930**	3,142
Depreciation, Depletion and Amortization	16,17	**5,192**	4,871
Deferred Income Tax Expense (Recovery)	10	**(231)**	(474)
Unrealized (Gain) Loss on Risk Management	31	**(15)**	12
Unrealized Foreign Exchange (Gain) Loss	7	**(424)**	550
Realized Foreign Exchange (Gain) Loss on Non-Operating Items		**23**	—
(Gain) Loss on Divestiture of Assets	4,8	**(87)**	(119)
Re-measurement of Contingent Payments		**—**	30
Unwinding of Discount on Decommissioning Liabilities	23	**243**	225
(Income) Loss From Equity-Accounted Affiliates	18	**(53)**	(66)
Distributions Received From Equity-Accounted Affiliates	18	**135**	172
Stock-Based Compensation, Net of Payments		**163**	(145)
Other		**(5)**	(34)
Settlement of Decommissioning Liabilities	23	**(280)**	(234)
Net Change in Non-Cash Working Capital	33	**(363)**	1,305
Cash From (Used in) Operating Activities		**8,228**	9,235
Investing Activities			
Acquisitions, Net of Cash Acquired	4	**(3,666)**	(22)
Capital Investment	1	**(4,907)**	(5,015)
Proceeds From Divestitures	8	**1,891**	46
Acquisition of Ownership Interest in MEG Energy Corp.	4	**(752)**	—
Net Change in Investments and Other		**(7)**	(80)
Net Change in Non-Cash Working Capital	33	**(236)**	(55)
Cash From (Used in) Investing Activities		**(7,677)**	(5,126)
Net Cash Provided (Used) Before Financing Activities		**551**	4,109
Financing Activities	33		
Net Issuance (Repayment) of Short-Term Borrowings		**152**	5
Issuance of Long-Term Debt	22	**5,265**	—
Repayment of Long-Term Debt	22	**(2,324)**	—
Principal Repayment of Leases	17	**(350)**	(299)
Net Proceeds (Repayment) on Repurchase Agreements		**413**	—
Common Shares Issued Under Stock Option Plans		**16**	52
Purchase of Common Shares Under NCIB	26	**(1,995)**	(1,445)
Purchase of Common Shares Under Employee Benefit Plan	26	**(155)**	(43)
Redemption of Preferred Shares	26	**(350)**	(250)
Proceeds From Exercise of Warrants		**16**	26
Dividends Paid	11	**(1,437)**	(1,551)
Cash From (Used in) Financing Activities		**(749)**	(3,505)
Effect of Foreign Exchange on Cash and Cash Equivalents		**(155)**	262
Increase (Decrease) in Cash and Cash Equivalents		**(353)**	866
Cash and Cash Equivalents, Beginning of Year		**3,093**	2,227
Cash and Cash Equivalents, End of Year		**2,740**	3,093

See accompanying Notes to the Consolidated Financial Statements.

1. DESCRIPTION OF BUSINESS AND SEGMENTED DISCLOSURES

Cenovus Energy Inc. ("Cenovus" or the "Company") is an integrated energy company with crude oil and natural gas production operations in Canada and the Asia Pacific region, and upgrading, refining and marketing operations in Canada and the United States ("U.S.").

Cenovus is incorporated under the Canada Business Corporations Act and its common shares are listed on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange. Cenovus's cumulative redeemable preferred shares series 1 and 2 are listed on the TSX. The executive and registered office is located at 4100, 225 6 Avenue S.W., Calgary, Alberta, Canada, T2P 1N2. Information on the Company's basis of preparation for these Consolidated Financial Statements is found in Note 2.

Management has determined the operating segments based on information regularly reviewed for the purposes of decision making, allocating resources and assessing operational performance by Cenovus's chief operating decision maker. The Company's operating segments are aggregated based on their geographic locations, the nature of the businesses or a combination of these factors. The Company evaluates the financial performance of its operating segments primarily based on operating margin.

The Company operates through the following reportable segments:

Upstream Segments

- **Oil Sands,** includes the development and production of bitumen and heavy oil in northern Alberta and Saskatchewan. Cenovus's oil sands assets include Foster Creek, Sunrise, Lloydminster thermal and Lloydminster conventional heavy oil assets, as well as Christina Lake, which includes the results from the acquisition of MEG Energy Corp. ("MEG") through a plan of arrangement (the "MEG Acquisition") (see Note 4). Cenovus jointly owns and operates pipeline gathering systems and terminals through the equity-accounted investment in Husky Midstream Limited Partnership ("HMLP"). The sale and transportation of Cenovus's production and third-party commodity trading volumes are managed and marketed through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Conventional,** includes assets rich in natural gas liquids ("NGLs") and natural gas in Alberta and British Columbia in the Edson, Clearwater and Rainbow Lake operating areas, in addition to the Northern Corridor, which includes Elmworth and Wapiti. The segment also includes interests in numerous natural gas processing facilities. Cenovus's NGLs and natural gas production is marketed and transported, with additional third-party commodity trading volumes, through access to capacity on third-party pipelines, export terminals and storage facilities. These provide flexibility for market access to optimize product mix, delivery points, transportation commitments and customer diversification.
- **Offshore,** includes offshore operations, exploration and development activities in the east coast of Canada and the Asia Pacific region, representing China and the equity-accounted investment in Husky-CNOOC Madura Limited ("HCML"), which is engaged in the exploration for, and production of, NGLs and natural gas in offshore Indonesia.

Downstream Segments

- **Canadian Refining,** includes the owned and operated Lloydminster upgrading and asphalt refining complex, which converts heavy oil and bitumen into synthetic crude oil, diesel, asphalt and other ancillary products. Cenovus also owns and operates the Bruderheim crude-by-rail terminal and two ethanol plants. The Company's commercial fuels business across Canada is included in this segment. Cenovus markets its production and third-party commodity trading volumes in an effort to use its integrated network of assets to maximize value.
- **U.S. Refining,** includes the refining of crude oil to produce gasoline, diesel, jet fuel, asphalt and other products at the wholly-owned Lima, Superior and Toledo refineries. On September 30, 2025, Cenovus divested its entire 50 percent interest in the jointly-owned Wood River and Borger refineries held through WRB Refining LP ("WRB") with operator Phillips 66 (see Note 8). The U.S. Refining segment included the WRB results up to the date of divestiture. Cenovus markets its own and third-party refined products.

Corporate and Eliminations

Corporate and Eliminations, includes Cenovus-wide costs for general and administrative, financing activities, gains and losses on risk management for corporate-related derivative instruments and foreign exchange. Eliminations include adjustments for feedstock and internal usage of crude oil, natural gas, condensate, other NGLs and refined products between segments; transloading services provided to the Oil Sands segment by the Company's crude-by-rail terminal; the sale of condensate extracted from blended crude oil production in the Canadian Refining segment and sold to the Oil Sands segment; and unrealized profits in inventory. Eliminations are recorded based on market prices.

A) Results of Operations – Segment and Operational Information

	Upstream							
	Oil Sands		Conventional		Offshore		Total	
For the years ended December 31,	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Gross Sales								
External Sales	**21,541**	21,857	**1,305**	1,211	**1,508**	1,572	**24,354**	24,640
Intersegment Sales	**6,786**	6,590	**1,355**	1,848	**—**	—	**8,141**	8,438
	28,327	28,447	**2,660**	3,059	**1,508**	1,572	**32,495**	33,078
Royalties	**(2,920)**	(3,274)	**(55)**	(76)	**(80)**	(99)	**(3,055)**	(3,449)
Revenues	**25,407**	25,173	**2,605**	2,983	**1,428**	1,473	**29,440**	29,629
Expenses								
Purchased Product	**2,886**	1,851	**1,337**	1,823	**—**	—	**4,223**	3,674
Transportation and Blending	**10,875**	11,000	**351**	320	**17**	11	**11,243**	11,331
Operating	**2,754**	2,511	**464**	555	**349**	423	**3,567**	3,489
Realized (Gain) Loss on Risk Management	**8**	20	**(4)**	(6)	**—**	—	**4**	14
Operating Margin	**8,884**	9,791	**457**	291	**1,062**	1,039	**10,403**	11,121
Unrealized (Gain) Loss on Risk Management	**3**	(16)	**(4)**	4	**—**	—	**(1)**	(12)
Depreciation, Depletion and Amortization	**3,433**	3,117	**479**	442	**440**	563	**4,352**	4,122
Exploration Expense	**11**	2	**22**	1	**8**	66	**41**	69
(Income) Loss From Equity-Accounted Affiliates	**(38)**	(14)	**—**	2	**(31)**	(53)	**(69)**	(65)
Segment Income (Loss)	**5,475**	6,702	**(40)**	(158)	**645**	463	**6,080**	7,007

	Downstream					
	Canadian Refining		U.S. Refining		Total	
For the years ended December 31,	**2025**	2024	**2025**	2024	**2025**	2024
Gross Sales						
External Sales	**4,282**	4,787	**24,115**	28,299	**28,397**	33,086
Intersegment Sales	**797**	523	**3**	9	**800**	532
	5,079	5,310	**24,118**	28,308	**29,197**	33,618
Royalties	**—**	—	**—**	—	**—**	—
Revenues	**5,079**	5,310	**24,118**	28,308	**29,197**	33,618
Expenses						
Purchased Product	**4,128**	4,483	**21,727**	25,769	**25,855**	30,252
Transportation and Blending	**—**	—	**—**	—	**—**	—
Operating	**597**	907	**2,546**	2,763	**3,143**	3,670
Realized (Gain) Loss on Risk Management	**—**	—	**(6)**	8	**(6)**	8
Operating Margin	**354**	(80)	**(149)**	(232)	**205**	(312)
Unrealized (Gain) Loss on Risk Management	**—**	—	**(5)**	8	**(5)**	8
Depreciation, Depletion and Amortization	**178**	185	**566**	462	**744**	647
Exploration Expense	**—**	—	**—**	—	**—**	—
(Income) Loss From Equity-Accounted Affiliates	**—**	—	**—**	—	**—**	—
Segment Income (Loss)	**176**	(265)	**(710)**	(702)	**(534)**	(967)

	Corporate and Eliminations		Consolidated	
For the years ended December 31,	**2025**	2024	**2025**	2024
Gross Sales				
External Sales	**—**	—	**52,751**	57,726
Intersegment Sales	**(8,941)**	(8,970)	**—**	—
	(8,941)	(8,970)	**52,751**	57,726
Royalties	**—**	—	**(3,055)**	(3,449)
Revenues	**(8,941)**	(8,970)	**49,696**	54,277
Expenses				
Purchased Product	**(7,910)**	(7,823)	**22,168**	26,103
Transportation and Blending	**(723)**	(793)	**10,520**	10,538
Purchased Product, Transportation and Blending	**(8,633)**	(8,616)	**32,688**	36,641
Operating	**(374)**	(318)	**6,336**	6,841
Realized (Gain) Loss on Risk Management	**(20)**	24	**(22)**	46
Unrealized (Gain) Loss on Risk Management	**(9)**	16	**(15)**	12
Depreciation, Depletion and Amortization	**96**	102	**5,192**	4,871
Exploration Expense	**—**	—	**41**	69
(Income) Loss From Equity-Accounted Affiliates	**16**	(1)	**(53)**	(66)
Segment Income (Loss)	**(17)**	(177)	**5,529**	5,863
General and Administrative	**812**	794	**812**	794
Finance Costs, Net	**569**	514	**569**	514
Integration, Transaction and Other Costs	**234**	166	**234**	166
Foreign Exchange (Gain) Loss, Net	**(361)**	462	**(361)**	462
(Gain) Loss on Divestiture of Assets	**(87)**	(119)	**(87)**	(119)
Re-measurement of Contingent Payments	**—**	30	**—**	30
Other (Income) Loss, Net	**(115)**	(55)	**(115)**	(55)
	1,052	1,792	**1,052**	1,792
Earnings (Loss) Before Income Tax			**4,477**	4,071
Income Tax Expense (Recovery)			**547**	929
Net Earnings (Loss)			**3,930**	3,142

B) External Sales by Product

	Upstream							
	Oil Sands		Conventional		Offshore		Total	
For the years ended December 31,	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Crude Oil	**20,215**	21,183	**215**	207	**401**	321	**20,831**	21,711
Natural Gas and Other	**318**	332	**864**	648	**850**	925	**2,032**	1,905
NGLs [(1)]	**1,008**	342	**226**	356	**257**	326	**1,491**	1,024
External Sales	**21,541**	21,857	**1,305**	1,211	**1,508**	1,572	**24,354**	24,640

	Downstream					
	Canadian Refining		U.S. Refining		Total	
For the years ended December 31,	**2025**	2024	**2025**	2024	**2025**	2024
Gasoline	**234**	429	**11,640**	13,792	**11,874**	14,221
Distillates [(2)]	**1,422**	1,484	**9,170**	10,632	**10,592**	12,116
Synthetic Crude Oil	**1,567**	1,814	**—**	—	**1,567**	1,814
Asphalt	**506**	548	**924**	1,029	**1,430**	1,577
Other Products and Services	**553**	512	**2,381**	2,846	**2,934**	3,358
External Sales	**4,282**	4,787	**24,115**	28,299	**28,397**	33,086

(1) Third-party condensate sales are included within NGLs.
(2) Includes diesel and jet fuel.

C) Geographical Information

For the years ended December 31,	Revenues [1] 2025	2024
Canada	**23,789**	26,791
United States	**24,895**	26,333
China	**1,012**	1,153
Consolidated	**49,696**	54,277

(1) Revenues from external customers by country are classified based on the jurisdiction in which the selling entities are located.

As at December 31,	Non-Current Assets [1] 2025	2024
Canada	**47,641**	37,006
United States	**2,514**	5,902
China	**939**	1,249
Indonesia	**203**	295
Consolidated	**51,297**	44,452

(1) Includes exploration and evaluation ("E&E") assets, property, plant and equipment ("PP&E"), right-of-use ("ROU") assets, income tax receivable, investments in equity-accounted affiliates, precious metals, intangible assets and goodwill.

Major Customers

In connection with the marketing and sale of Cenovus's own and purchased crude oil, NGLs, natural gas and refined products for the year ended December 31, 2025, Cenovus had two customers (2024 – two) that individually accounted for more than 10 percent of its consolidated gross sales. Sales to these customers, recognized as major international energy companies with investment grade credit ratings, were approximately $11.7 billion and $5.8 billion, respectively (2024 – $17.7 billion and $8.1 billion, respectively), and are reported across all of the Company's operating segments.

D) Assets by Segment

As at December 31,	E&E Assets 2025	2024	PP&E 2025	2024	ROU Assets 2025	2024
Oil Sands	**568**	461	**34,149**	24,646	**1,204**	1,018
Conventional	**—**	15	**2,202**	2,230	**44**	57
Offshore	**7**	8	**4,008**	3,365	**180**	95
Canadian Refining	**—**	—	**2,452**	2,511	**50**	39
U.S. Refining	**—**	—	**2,238**	5,538	**287**	342
Corporate and Eliminations	**—**	—	**211**	278	**388**	399
Consolidated	**575**	484	**45,260**	38,568	**2,153**	1,950

As at December 31,	Goodwill 2025	2024	Total Assets 2025	2024
Oil Sands	**2,912**	2,923	**42,505**	31,668
Conventional	**—**	—	**2,579**	2,610
Offshore	**—**	—	**4,756**	4,089
Canadian Refining	**—**	—	**2,831**	2,901
U.S. Refining	**—**	—	**4,698**	9,517
Corporate and Eliminations	**—**	—	**6,055**	5,754
Consolidated	**2,912**	2,923	**63,424**	56,539

E) Capital Expenditures [1]

For the years ended December 31,	**2025**	2024
Capital Investment		
Oil Sands	**2,944**	2,714
Conventional	**453**	421
Offshore		
Atlantic	**848**	1,077
Asia Pacific	**86**	68
Total Upstream	**4,331**	4,280
Canadian Refining	**117**	208
U.S. Refining	**442**	488
Total Downstream	**559**	696
Corporate and Eliminations	**17**	39
	4,907	5,015
Acquisitions		
Oil Sands (Note 4)	**10,120**	9
Conventional	**44**	13
	10,164	22
Total Capital Expenditures	**15,071**	5,037

(1) Includes expenditures on PP&E, E&E assets and capitalized interest. Excludes capital expenditures related to the Company's joint ventures.

2. BASIS OF PREPARATION AND STATEMENT OF COMPLIANCE

These Consolidated Financial Statements are presented in Canadian dollars. All references to C$ or $ are to Canadian dollars and references to US$ are to U.S. dollars.

These Consolidated Financial Statements were prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") (the "IFRS Accounting Standards") and interpretations of the International Financial Reporting Interpretations Committee.

These Consolidated Financial Statements were prepared on a historical cost basis, except as detailed in the Company's accounting policies as disclosed in Note 35.

These Consolidated Financial Statements were approved by the Board of Directors effective February 18, 2026.

3. CRITICAL ACCOUNTING JUDGMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

The timely preparation of the Consolidated Financial Statements in accordance with IFRS Accounting Standards requires that Management make estimates and assumptions, and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the Consolidated Financial Statements, and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as of the date of the Consolidated Financial Statements. The estimated fair value of financial assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

A) Critical Judgments in Applying Accounting Policies

Critical judgments are those judgments made by Management in the process of applying accounting policies that have the most significant effect on the amounts recorded in the Company's Consolidated Financial Statements.

Identification of Cash-Generating Units

Cash-generating units ("CGUs") are defined as the lowest level of integrated assets for which there are separately identifiable cash flows that are largely independent of cash flows from other assets or groups of assets. The classification of assets and allocation of corporate assets into CGUs requires significant judgment and interpretation. Factors considered in the classification include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure, and the manner in which Management monitors and makes decisions about its operations. The recoverability of the Company's upstream, refining, crude-by-rail, railcars, storage tanks and corporate assets are assessed at the CGU level. As such, the determination of a CGU could have a significant impact on impairment losses and impairment reversals.

Assessment of Impairment Indicators or Impairment Reversals

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount may exceed its recoverable amount. Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. The identification of indicators of impairment or reversal of impairment requires significant judgment.

Exploration and Evaluation Assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Factors such as drilling results, future capital programs, future operating expenses, as well as estimated reserves and resources are considered. In addition, Management uses judgment to determine when E&E assets are reclassified to PP&E. In making this determination, various factors are considered, including the existence of reserves, and whether the appropriate approvals have been received from regulatory bodies and the Company's internal approval process.

Joint Arrangements

The classification of a joint arrangement that is held in a separate vehicle as either a joint operation or a joint venture requires judgment.

On September 30, 2025, Cenovus divested its entire 50 percent interest in WRB, which was a jointly-controlled entity (see Note 8). The joint arrangement met the definition of a joint operation under IFRS 11, *"Joint Arrangements"* ("IFRS 11"); therefore, the Company recognized its share of the assets, liabilities, revenues and expenses in its consolidated results up to the date of divestiture.

In determining the classification of its joint arrangement under IFRS 11, the Company considered the following:

- The original intention of the joint arrangement was to form an integrated North American heavy oil business. Partnerships are "flow-through" entities.
- The agreements required the partners to make contributions if funds were insufficient to meet the obligations or liabilities of the corporation and partnership. The past and future development of WRB was dependent on funding from the partners by way of capital contribution commitments, notes payable and loans.
- WRB had third-party debt facilities to cover short-term working capital requirements.
- Phillips 66, as operator of WRB, either directly or through wholly-owned subsidiaries, provided marketing services, purchased necessary feedstock, and arranged for transportation and storage, on the partners' behalf as the agreements prohibited the partners from undertaking these roles themselves. In addition, the joint arrangement did not have employees and, as such, was not capable of performing these roles.
- In the arrangement, output was taken by the partners, indicating that the partners had the rights to the economic benefits of the assets and the obligation for funding the liabilities of the arrangement.

B) Key Sources of Estimation Uncertainty

Critical accounting estimates are those estimates that require Management to make particularly subjective or complex judgments about matters that are inherently uncertain. Estimates and underlying assumptions are reviewed on an ongoing basis, and any revisions to accounting estimates are recorded in the period in which the estimates are revised.

The evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels could change assumptions used to determine the recoverable amount of the Company's PP&E and E&E assets and could affect the carrying value of those assets, may affect future development or viability of exploration prospects, may curtail the expected useful lives of oil and gas assets thereby accelerating depreciation charges and may accelerate decommissioning obligations increasing the present value of the associated provisions. The timing in which global energy markets transition from carbon-based sources to alternative energy is highly uncertain. Environmental considerations are built into estimates through the use of key assumptions used to estimate fair value including forward commodity prices, forward crack spreads, net of renewable identification numbers ("RINs"), and discount rates. The energy transition could impact the future prices of commodities. Pricing assumptions used in the determination of recoverable amounts incorporate market expectations and the evolving worldwide demand for energy.

The following are the key estimates, assumptions and judgments at the end of the reporting period that, if changed, could result in a material adjustment to the carrying amount of assets and liabilities within the next financial year.

Crude Oil and Natural Gas Reserves

There are a number of inherent uncertainties associated with estimating crude oil and natural gas reserves. Reserves estimates are dependent upon variables including the expected future production volumes, future development and operating expenses, forward commodity prices, estimated royalty payments and taxes. Changes in these variables could significantly impact the reserves estimates which would affect the impairment test recoverable amount and depreciation, depletion and amortization ("DD&A") expense of the Company's crude oil and natural gas assets in the Oil Sands, Conventional and Offshore segments. The Company's reserves are evaluated annually and reported to the Company by its independent qualified reserves evaluators ("IQREs").

Recoverable Amounts

Determining the recoverable amount of a CGU or an individual asset requires the use of estimates and assumptions, which are subject to change as new information becomes available. For the Company's upstream assets, these estimates include quantity of reserves, expected future production volumes, future development and operating expenses, forward commodity prices and discount rates. Recoverable amounts for the Company's downstream assets use assumptions such as refined product production, forward crude oil prices, forward crack spreads, net of RINs, future operating expenses, future capital expenditures and discount rates. Changes in assumptions used in determining the recoverable amount could affect the carrying value of the related assets.

Decommissioning Costs

Provisions are recorded for the future decommissioning and restoration of the Company's upstream assets, refining assets and crude-by-rail terminal at the end of their economic lives. Management uses judgment to assess the existence of liabilities and estimate the future value. The actual cost of decommissioning and restoration is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration. In addition, Management determines the appropriate discount rate at the end of each reporting period. This discount rate, which is credit-adjusted, is used to determine the present value of the estimated future cash outflows required to settle the obligation and may change in response to numerous market factors.

Fair Value of Assets Acquired and Liabilities Assumed in a Business Combination

The fair value of assets acquired, liabilities assumed and assets given up in a business combination, including contingent consideration and goodwill, if any, is estimated based on information available at the date of acquisition. Various valuation techniques are applied for measuring fair value including market comparable transactions and discounted cash flows. For the Company's upstream assets, key assumptions in the discounted cash flow models used to estimate fair value include forward commodity prices, expected future production volumes, quantity of reserves, discount rates, and future development and operating expenses. Estimated production volumes and quantity of reserves for acquired oil and gas properties were developed by internal geology and engineering professionals, and IQREs. Changes in these variables could significantly impact the carrying value of the net assets acquired.

Income Tax Provisions

The determination of the Company's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. There are usually a number of tax matters under review; therefore, income taxes are subject to measurement uncertainty.

Deferred income tax assets are recorded to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flow to offset the tax assets when the reversal occurs and the application of tax laws. There are some transactions for which the ultimate tax determination is uncertain. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the Consolidated Financial Statements of future periods.

4. MEG ENERGY CORP. ACQUISITION

A) Summary of the Acquisition

On November 13, 2025, Cenovus completed the MEG Acquisition pursuant to which Cenovus acquired all the issued and outstanding common shares of MEG, other than common shares of MEG already owned by Cenovus, for total purchase consideration of $7.1 billion, consisting of $3.4 billion in cash, 143.9 million Cenovus common shares and $32 million of assumed stock-based compensation. Prior to closing the MEG Acquisition, the Company held an aggregate of 25.0 million common shares of MEG with an acquisition-date fair value of $775 million.

The MEG Acquisition provides Cenovus with additional oil sands assets that are directly adjacent to the Company's Christina Lake asset and are reported under the Christina Lake results in the Oil Sands segment.

The MEG Acquisition was accounted for using the acquisition method pursuant to IFRS 3, *"Business Combinations"* ("IFRS 3"). Under the acquisition method, assets and liabilities are recorded at fair value on the date of acquisition, with the exception of ROU assets, lease liabilities, income taxes and stock-based compensation. The total consideration is allocated to the assets acquired and liabilities assumed. The excess of consideration given over the fair value of the net assets acquired, if any, is recorded as goodwill. In accordance with the step acquisition treatment of IFRS 3, the previously held interest in MEG is required to be re-measured to fair value at the acquisition date with any gain or loss recognized in net earnings (loss).

B) Identifiable Assets Acquired and Liabilities Assumed

The preliminary purchase price allocation is based on Management's best estimate of fair value. Upon finalizing the fair value of net assets acquired, adjustments to initial estimates, including goodwill, may be required.

The following table summarizes the details of the consideration and the recognized amounts of assets acquired and liabilities assumed at the date of the acquisition.

As at	November 13, 2025
Consideration	
Cash	**3,441**
Common Shares [1]	**3,667**
Stock-Based Compensation	**32**
Total Purchase Consideration	**7,140**
Fair Value of Pre-Existing Ownership Interest	**775**
Total Consideration	**7,915**
Identifiable Assets Acquired and Liabilities Assumed	
Cash	**36**
Accounts Receivable and Accrued Revenues	**571**
Income Tax Receivable	**13**
Inventories	**499**
Exploration and Evaluation Assets	**174**
Property, Plant and Equipment	**9,709**
Right-of-Use Assets	**301**
Other Assets	**13**
Accounts Payable and Accrued Liabilities	**(444)**
Income Tax Payable	**(3)**
Long-Term Debt	**(843)**
Lease Liabilities	**(366)**
Decommissioning Liabilities	**(184)**
Other Liabilities	**(27)**
Deferred Income Tax Liabilities, Net	**(1,534)**
Total Identifiable Net Assets	**7,915**
Goodwill	**—**

(1) Based on the November 13, 2025, opening share price of $25.48, as reported on the TSX.

The fair value and gross contractual amount of acquired accounts receivable and accrued revenues was $571 million, all of which was collected.

C) Fair Value of Pre-Existing Ownership Interest

The acquisition-date fair value of the previously held MEG common shares was estimated to be $775 million and the net carrying value was $752 million. Cenovus recognized a revaluation gain of $23 million, which is recorded in gain (loss) on divestiture of assets in net earnings (loss).

D) Transaction Costs

For the year ended December 31, 2025, integration and transaction costs related to the acquisition of $72 million were recognized in net earnings (loss).

E) Revenue and Profit Contribution

The acquired business contributed revenues of $623 million and segment income of $29 million for the period from November 13, 2025, to December 31, 2025.

If the closing of the MEG Acquisition had occurred on January 1, 2025, Cenovus's consolidated pro forma revenues and segment income for the year ended December 31, 2025, would have been $53.4 billion and $6.0 billion, respectively. These amounts were calculated using results from the acquired business adjusting them for additional DD&A that would be charged assuming the fair value adjustments to PP&E had applied from January 1, 2025, and differences in accounting policies. This pro forma information is not necessarily indicative of the results that would have been obtained if the MEG Acquisition had actually occurred on January 1, 2025.

5. GENERAL AND ADMINISTRATIVE

For the years ended December 31,	**2025**	2024
Salaries and Benefits	**282**	269
Administrative and Other	**339**	399
Stock-Based Compensation Expense (Recovery) (Note 28)	**191**	126
	812	794

6. FINANCE COSTS, NET

For the years ended December 31,	**2025**	2024
Interest Expense – Short-Term Borrowings and Long-Term Debt	**333**	307
Net Premium (Discount) on Redemption of Long-Term Debt [(1)]	**9**	—
Interest Expense – Lease Liabilities (Note 17)	**171**	162
Unwinding of Discount on Decommissioning Liabilities (Note 23)	**243**	225
Other	**40**	35
Capitalized Interest	**(86)**	(45)
Finance Costs	**710**	684
Interest Income	**(141)**	(170)
	569	514

(1) Includes the premium on redemption, transaction costs and the amortization of associated fair value adjustments.

7. FOREIGN EXCHANGE (GAIN) LOSS, NET

For the years ended December 31,	**2025**	2024
Unrealized Foreign Exchange (Gain) Loss on Translation of:		
U.S. Dollar Debt	**(312)**	442
Other	**(112)**	108
Unrealized Foreign Exchange (Gain) Loss	**(424)**	550
Realized Foreign Exchange (Gain) Loss	**63**	(88)
	(361)	462

8. DIVESTITURES

A) 2025 Divestitures

On September 30, 2025, the Company divested its entire 50 percent interest in WRB, which was reported in the U.S. Refining segment, for proceeds of US$1.3 billion (C$1.9 billion) after closing adjustments. The before-tax gain of $119 million on divestiture reflects the difference between proceeds and the Company's share of net assets of $3.0 billion and a cumulative foreign currency translation adjustment directly attributable to WRB of $1.3 billion (see Note 27) that was recycled upon divestiture.

The Company also closed the sale of certain Lloydminster thermal assets in the Oil Sands segment for total proceeds of $75 million in cash and variable consideration of $29 million, which resulted in a before-tax loss of $58 million.

B) 2024 Divestitures

The Company closed a transaction with Athabasca Oil Corporation ("Athabasca"), to create the jointly-controlled Duvernay Energy Corporation ("Duvernay"). Cenovus contributed non-monetary assets with a fair value of $94 million and cash of $18 million, before closing adjustments, in exchange for a 30 percent equity interest in Duvernay. The Company recognized an investment of $84 million in Duvernay and a before-tax gain on divestiture of assets of $65 million, reflecting the difference between the carrying value and fair value of contributed assets to the extent of Athabasca's share.

The Company also closed the sale of non-core assets in its Conventional segment for net proceeds of $39 million and recorded a before-tax gain of $51 million.

9. IMPAIRMENT CHARGES AND REVERSALS

A) Upstream Cash-Generating Units

Impairment Charges

The Company tested CGUs with associated goodwill for impairment as at December 31, 2025, and 2024, and there were no impairments. No impairment indicators were identified for the remaining CGUs as at December 31, 2025, and December 31, 2024.

Key Assumptions

The recoverable amounts (Level 3) of Cenovus's Oil Sands CGUs with associated goodwill were estimated using fair value less costs of disposal ("FVLCOD"). Key assumptions used to estimate the present value of future net cash flows from reserves include expected future production volumes, quantity of reserves, forward commodity prices, and future development and operating expenses, all consistent with Cenovus's IQREs, as well as discount rates. Fair values for producing properties were calculated based on discounted after-tax cash flows of proved and probable reserves using the IQRE forward prices and cost estimates as at December 31, 2025. All reserves were evaluated as at December 31, 2025, and December 31, 2024, by the Company's IQREs.

Crude Oil, NGLs and Natural Gas Prices

The forward commodity prices as at December 31, 2025, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2026	**2027**	**2028**	**2029**	**2030**	**Average Annual Increase Thereafter** (percent)
WTI [1] (US$/bbl) [2]	**59.92**	**65.10**	**70.28**	**71.93**	**73.37**	**2.00**
WCS [3] (C$/bbl)	**65.13**	**70.43**	**76.90**	**78.71**	**80.29**	**2.00**
Condensate at Edmonton (C$/bbl)	**80.01**	**86.19**	**92.83**	**95.04**	**96.94**	**2.00**
Alberta Energy Company Natural Gas (C$/Mcf) [4]	**3.00**	**3.30**	**3.49**	**3.58**	**3.65**	**2.00**

(1) West Texas Intermediate ("WTI").
(2) Barrel ("bbl").
(3) Western Canadian Select at Hardisty ("WCS").
(4) One thousand cubic feet ("Mcf").

The forward commodity prices as at December 31, 2024, used to determine future cash flows from crude oil, NGLs and natural gas reserves were:

	2025	2026	2027	2028	2029	Average Annual Increase Thereafter (percent)
WTI (US$/bbl)	71.58	74.48	75.81	77.66	79.22	2.00
WCS (C$/bbl)	82.69	84.27	83.81	85.70	87.45	2.00
Condensate at Edmonton (C$/bbl)	100.14	100.72	100.24	102.73	104.79	2.00
Alberta Energy Company Natural Gas (C$/Mcf)	2.36	3.33	3.48	3.69	3.76	2.00

Discount Rates

Discounted future cash flows were determined by applying a discount rate of 13 percent (2024 – 14 percent).

Sensitivities

A one percent (2024 – one percent) increase in the discount rate or a five percent (2024 – five percent) decrease in forward commodity price estimates would not impact the results of the impairment tests performed.

B) Downstream Cash-Generating Units

i) 2025 Impairment Charges and Reversals

As at December 31, 2025, there were no indicators of impairment or impairment reversals for the Company's downstream CGUs.

ii) 2024 Impairment Charges and Reversals

As at December 31, 2024, lower forward Chicago 3-2-1 crack spreads, net of RINs, that would result in lower margins for refined products was identified as an indicator of impairment for the Lima, Toledo and Wood River CGUs. As a result, these CGUs were tested for impairment.

The recoverable amounts of the Lima, Toledo and Wood River CGUs were in excess of their respective carrying amounts and no impairment was recorded. There were no indicators of impairment for the remaining downstream CGUs and no indicators of impairment reversal for the Superior and Borger CGUs.

Key Assumptions

The recoverable amount (Level 3) of each of the CGUs were determined using FVLCOD. FVLCOD was calculated based on discounted after-tax cash flows using forward prices and cost estimates. Key assumptions in the determination of future cash flows included refined product production, forward crude oil prices, forward crack spreads, net of RINs, future capital expenditures, future operating costs and discount rates. Forward prices were based on third-party consultant forecasts.

Crude Oil and Select Refining Benchmark Prices

As at December 31, 2024, the forward prices used to determine future cash flows were:

(US$/bbl)	2025	2026	2027	2028	2029
WTI	77.68	77.07	78.74	81.51	83.14
Differential WTI – WCS	(14.17)	(15.34)	(15.71)	(16.62)	(17.11)
Chicago 3-2-1 Crack Spread	20.01	21.97	22.60	23.87	24.66
Renewable Identification Numbers	6.79	7.31	8.05	8.69	9.03

Subsequent estimated cash flows were determined using a pricing growth rate between one percent and six percent up to the year 2034.

Discount Rates

Discounted future cash flows were determined by applying a discount rate between 15 percent and 16 percent based on the individual characteristics of the CGU and on the economic and operating factors.

Sensitivities

The sensitivity analysis below shows the impact that a change in the discount rate or in forward prices would have had on the impairment amount as at December 31, 2024, for the U.S. Refining CGUs:

	Increase (Decrease) to Impairment Amount	
	One Percent Increase in the Discount Rate	Five Percent Decrease in the Forward Prices
Lima and Wood River CGUs	214	619

For the Toledo CGU, a one percent increase in the discount rate or a five percent decrease in forward prices would not result in an impairment.

10. INCOME TAXES

A) Income Tax Expense (Recovery)

For the years ended December 31,	**2025**	2024
Current Tax		
Canada	**540**	1,141
United States	**(1)**	9
Asia Pacific	**198**	214
Other International	**41**	39
Total Current Tax Expense (Recovery)	**778**	1,403
Deferred Tax Expense (Recovery)	**(231)**	(474)
	547	929

The following table reconciles income taxes calculated at the consolidated combined federal and provincial Canadian statutory rate with the recorded income taxes:

For the years ended December 31,	**2025**	2024
Earnings (Loss) Before Income Tax	**4,477**	4,071
Canadian Statutory Rate (percent)	**23.7**	23.7
Expected Income Tax Expense (Recovery)	**1,061**	965
Effect on Taxes Resulting From:		
Statutory and Other Rate Differences	**(37)**	(34)
Non-Taxable Capital (Gains) Losses	**(34)**	45
Non-Recognition of Capital (Gains) Losses	**(34)**	45
Adjustments Arising From Prior Year Tax Filings	**(37)**	(31)
Recognition of U.S. Tax Basis	**(54)**	(77)
Cumulative Translation Adjustment	**(298)**	—
Other	**(20)**	16
Total Tax Expense (Recovery)	**547**	929
Effective Tax Rate (percent)	**12.2**	22.8

The effective tax rate for 2025 was 12.2 percent (2024 – 22.8 percent). The lower effective tax rate in 2025 is primarily attributable to the reclassification of the cumulative foreign currency translation adjustment associated with the WRB divestiture (see Note 8), which is not tax effected.

In 2024, the Global Minimum Tax Act was enacted in Canada to implement the new global minimum tax framework ("Pillar Two"), which is to be applied retroactively to fiscal periods beginning on or after December 31, 2023. The Company is subject to Pillar Two and has applied the mandatory temporary exemption of IAS 12, *"Income Taxes"* and in turn, has not recognized the impacts of Pillar Two in the deferred income tax calculation.

For the year ended December 31, 2025, Pillar Two taxes did not have a material impact on net earnings. The Company is not expecting a material impact from jurisdictions where the Company operates that have not enacted Pillar Two legislation.

B) Deferred Income Tax Assets and Liabilities

The significant components of the Company's deferred income tax expense (recovery) for the years ended December 31, 2025, and December 31, 2024, and deferred income tax (assets) liabilities as at December 31, 2025, and December 31, 2024, are composed of the following:

	Deferred Income Tax Expense (Recovery)		Deferred Income Tax (Assets) Liabilities	
	2025	2024	**December 31, 2025**	December 31, 2024
Property, Plant and Equipment, Net	**(494)**	(632)	**6,825**	5,255
Right-of-Use Assets, Net	**(23)**	76	**520**	470
Decommissioning Liabilities	**(32)**	(85)	**(1,094)**	(1,018)
Unused Tax Losses	**336**	240	**(852)**	(740)
Lease Liabilities	**27**	(70)	**(743)**	(683)
Compensation and Benefits	**(20)**	34	**(140)**	(118)
Other	**(25)**	(37)	**(237)**	(185)
Net Deferred Income Tax Expense (Recovery) and Liability	**(231)**	(474)	**4,279**	2,981

Change in Deferred Income Tax Balances

	2025	2024
Net Deferred Income Tax Liability, Beginning of Year	**2,981**	3,492
Recognized in Deferred Income Tax Expense (Recovery)	**(231)**	(474)
Recognized in Other Comprehensive Income	**3**	15
Foreign Currency Translation Adjustment	**45**	(52)
Recognized on Acquisitions	**1,481**	—
Net Deferred Income Tax Liability, End of Year	**4,279**	2,981

Deferred Income Tax in Other Comprehensive Income

For the years ended December 31,	**2025**	2024
Deferred Income Tax Expense (Recovery) in OCI [(1)]		
Pension and Other Post-Retirement Benefits	**5**	5
Private Equity Instruments	**(2)**	10
	3	15

(1) Other comprehensive income ("OCI").

The deferred income tax asset of $1.6 billion as at December 31, 2025 (December 31, 2024 – $1.1 billion) represents net deductible temporary differences in the U.S. jurisdiction, which have been fully recognized as the probability of realization is expected due to forecasted taxable income. No deferred tax liability was recognized as at December 31, 2025, or December 31, 2024, on temporary differences associated with investments in subsidiaries and joint arrangements where the Company can control the timing of the reversal of the temporary difference and the reversal is not probable in the foreseeable future.

C) Tax Pools

The approximate amounts of tax pools available, including tax losses, are:

As at December 31,	**2025**	2024
Canada	**12,135**	10,086
United States	**8,730**	9,905
Asia Pacific	**338**	351
	21,203	20,342

As at December 31, 2025, the above tax pools included $38 million (December 31, 2024 – $197 million) of Canadian federal non-capital losses that expire no earlier than 2033, and $3.6 billion (December 31, 2024 – $3.0 billion) of U.S. federal net operating losses that have an indefinite carry forward period.

As at December 31, 2025, the Company had Canadian net capital losses totaling $96 million (December 31, 2024 – $85 million), which are available for carry forward to reduce future capital gains. The Company has not recognized $210 million (December 31, 2024 – $362 million) of deductible temporary differences associated with unrealized foreign exchange losses on its U.S. denominated debt.

11. PER SHARE AMOUNTS

A) Net Earnings (Loss) Per Common Share – Basic and Diluted

For the years ended December 31,	**2025**	2024
Net Earnings (Loss)	**3,930**	3,142
Effect of Cumulative Dividends on Preferred Shares	**(14)**	(36)
Net Earnings (Loss) – Basic	**3,916**	3,106
Effect of Stock-Based Compensation	**(1)**	3
Net Earnings (Loss) – Diluted	**3,915**	3,109
Basic – Weighted Average Number of Shares (thousands)	**1,809,902**	1,850,193
Dilutive Effect of Warrants	**2,782**	4,483
Dilutive Effect of Stock-Based Compensation	**7,177**	8,540
Diluted – Weighted Average Number of Shares (thousands)	**1,819,861**	1,863,216
Net Earnings (Loss) Per Common Share – Basic ($)	**2.16**	1.68
Net Earnings (Loss) Per Common Share – Diluted [(1)] ($)	**2.15**	1.67

(1) For the year ended December 31, 2025, 9.0 million common shares (2024 – 9.8 million) related to the assumed exercise of stock-based compensation were excluded from the calculation of dilutive net earnings (loss) per share as the effect was anti-dilutive.

B) Common Share Dividends

	2025		2024	
For the years ended December 31,	**Per Share**	**Amount**	Per Share	Amount
Base Dividends	**0.780**	**1,423**	0.680	1,255
Variable Dividends	**—**	**—**	0.135	251
Total Common Share Dividends Declared and Paid	**0.780**	**1,423**	0.815	1,506

The declaration of common share dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly.

On February 18, 2026, the Company's Board of Directors declared a first quarter base dividend of $0.200 per common share, payable on March 31, 2026, to common shareholders of record as at March 13, 2026.

C) Preferred Share Dividends

For the years ended December 31,	**2025**	2024
Series 1 First Preferred Shares	**7**	7
Series 2 First Preferred Shares	**1**	2
Series 3 First Preferred Shares	**—**	12
Series 5 First Preferred Shares	**2**	9
Series 7 First Preferred Shares	**4**	6
Total Preferred Share Dividends Declared	**14**	36

The declaration of preferred share dividends is at the sole discretion of the Company's Board of Directors and is considered quarterly.

For the year ended December 31, 2025, the Company paid $14 million in preferred share dividends (December 31, 2024 – $45 million).

On February 18, 2026, the Company's Board of Directors declared first quarter preferred share dividends of $2 million payable on March 31, 2026, to preferred shareholders of record as at March 13, 2026.

12. CASH AND CASH EQUIVALENTS

As at December 31,	**2025**	2024
Cash	**1,963**	2,723
Short-Term Investments	**777**	370
	2,740	3,093

Cash and cash equivalents include short-term investments, such as money market deposits or similar type instruments, with an original maturity of three months or less.

13. ACCOUNTS RECEIVABLE AND ACCRUED REVENUES

As at December 31,	**2025**	2024
Trade and Accruals	**3,046**	2,378
Prepaids and Deposits	**260**	187
Joint Operations Receivables	**36**	40
Other	**93**	9
	3,435	2,614

14. INVENTORIES

As at December 31,	**2025**	2024
Product		
Crude Oil	**1,643**	2,297
Diluent	**548**	401
Natural Gas and NGLs	**55**	77
Refined Products	**631**	1,176
Total Product	**2,877**	3,951
Parts and Supplies	**472**	545
	3,349	4,496

For the year ended December 31, 2025, approximately $36.6 billion of produced and purchased inventory, excluding DD&A, was recorded as an expense (2024 – approximately $42.8 billion).

As at December 31, 2025, and December 31, 2024, the Company had no product inventory write-downs.

15. EXPLORATION AND EVALUATION ASSETS, NET

	Total
As at December 31, 2023	738
Acquisitions	7
Additions	65
Transfer to PP&E (Note 16)	(285)
Write-downs [(1)]	(37)
Change in Decommissioning Liabilities	(5)
Exchange Rate Movements and Other	1
As at December 31, 2024	484

(1) For the year ended December 31, 2024, previously capitalized E&E costs of $37 million in the Offshore segment, was written off as exploration expense, as the carrying value was not considered to be recoverable.

	Total
As at December 31, 2024	**484**
Acquisitions (Note 4)	**174**
Additions	**87**
Transfer to PP&E (Note 16)	**(145)**
Write-downs [1]	**(25)**
Exchange Rate Movements and Other	**—**
As at December 31, 2025	**575**

(1) For the year ended December 31, 2025, previously capitalized E&E costs of $4 million and $21 million in the Oil Sands and Conventional segments, respectively, were written off as exploration expense, as the carrying value was not considered to be recoverable.

16. PROPERTY, PLANT AND EQUIPMENT, NET

	Crude Oil and Natural Gas Properties	Processing, Transportation and Storage Assets	Refining Assets	Other Assets [1]	Total
COST					
As at December 31, 2023	47,425	272	12,770	1,908	62,375
Acquisitions	15	—	—	—	15
Additions	4,215	3	661	71	4,950
Transfer from E&E (Note 15)	285	—	—	—	285
Change in Decommissioning Liabilities	312	2	4	(5)	313
Divestitures (Note 8)	(270)	—	—	(1)	(271)
Exchange Rate Movements and Other [2]	108	3	890	2	1,003
As at December 31, 2024	**52,090**	**280**	**14,325**	**1,975**	**68,670**
Acquisitions (Note 4)	**9,990**	**—**	**—**	**—**	**9,990**
Additions	**4,244**	**4**	**543**	**29**	**4,820**
Transfer from E&E (Note 15)	**145**	**—**	**—**	**—**	**145**
Change in Decommissioning Liabilities	**184**	**(1)**	**1**	**(4)**	**180**
Divestitures (Note 8)	**(593)**	**—**	**(7,243)**	**(18)**	**(7,854)**
Exchange Rate Movements and Other [2]	**(493)**	**(8)**	**(479)**	**(23)**	**(1,003)**
As at December 31, 2025	**65,567**	**275**	**7,147**	**1,959**	**74,948**
ACCUMULATED DEPRECIATION, DEPLETION AND AMORTIZATION					
As at December 31, 2023	17,975	129	5,667	1,354	25,125
Depreciation, Depletion and Amortization	3,949	11	539	81	4,580
Divestitures (Note 8)	(208)	—	—	—	(208)
Exchange Rate Movements and Other [2]	133	1	469	2	605
As at December 31, 2024	**21,849**	**141**	**6,675**	**1,437**	**30,102**
Depreciation, Depletion and Amortization	**4,154**	**11**	**617**	**79**	**4,861**
Divestitures (Note 8)	**(408)**	**—**	**(4,195)**	**(8)**	**(4,611)**
Exchange Rate Movements and Other [2]	**(387)**	**(9)**	**(263)**	**(5)**	**(664)**
As at December 31, 2025	**25,208**	**143**	**2,834**	**1,503**	**29,688**
CARRYING VALUE					
As at December 31, 2024	30,241	139	7,650	538	38,568
As at December 31, 2025	**40,359**	**132**	**4,313**	**456**	**45,260**

(1) Includes assets within the commercial fuels business, office furniture, fixtures, leasehold improvements, information technology and aircraft.
(2) Includes derecognition of fully depreciated and depleted assets no longer owned by Cenovus of $362 million (2024 – $6 million).

Assets Under Construction

PP&E includes the following amounts in respect of assets under construction that are not subject to DD&A:

As at December 31,	**2025**	2024
Crude Oil and Natural Gas Properties	**2,268**	3,359
Refining Assets	**147**	400
	2,415	3,759

17. LEASES

A) Right-of-Use Assets, Net

	Real Estate	Transportation and Storage Assets [1]	Refining Assets	Other Assets [2]	Total
COST					
As at December 31, 2023	588	1,964	161	70	2,783
Additions	2	317	—	51	370
Exchange Rate Movements and Other	2	111	17	4	134
As at December 31, 2024	**592**	**2,392**	**178**	**125**	**3,287**
Acquisitions (Note 4)	**9**	**292**	**—**	**—**	**301**
Additions	**8**	**153**	**—**	**15**	**176**
Modifications	**4**	**143**	**1**	**2**	**150**
Divestitures (Note 8)	**(1)**	**(175)**	**(23)**	**(9)**	**(208)**
Exchange Rate Movements and Other	**(1)**	**(170)**	**(8)**	**(11)**	**(190)**
As at December 31, 2025	**611**	**2,635**	**148**	**122**	**3,516**
ACCUMULATED DEPRECIATION					
As at December 31, 2023	156	863	65	19	1,103
Depreciation	35	198	21	37	291
Exchange Rate Movements and Other	2	(62)	8	(5)	(57)
As at December 31, 2024	**193**	**999**	**94**	**51**	**1,337**
Depreciation	**35**	**248**	**11**	**37**	**331**
Divestitures (Note 8)	**(1)**	**(144)**	**(8)**	**(9)**	**(162)**
Exchange Rate Movements and Other	**(4)**	**(126)**	**(5)**	**(8)**	**(143)**
As at December 31, 2025	**223**	**977**	**92**	**71**	**1,363**
CARRYING VALUE					
As at December 31, 2024	399	1,393	84	74	1,950
As at December 31, 2025	**388**	**1,658**	**56**	**51**	**2,153**

(1) Includes a pipeline, storage tanks, terminals, railcars, vessels, a natural gas processing plant and caverns.
(2) Includes assets in the commercial fuels business, fleet vehicles, camps and other equipment.

B) Lease Liabilities

	2025	2024
Lease Liabilities, Beginning of Year	**2,927**	2,658
Acquisitions (Note 4)	**366**	—
Additions	**174**	363
Interest Expense (Note 6)	**171**	162
Lease Payments	**(521)**	(461)
Divestitures (Note 8)	**(39)**	—
Modifications	**150**	91
Exchange Rate Movements and Other	**(53)**	114
Lease Liabilities, End of Year	**3,175**	2,927
Less: Current Portion	**369**	359
Long-Term Portion	**2,806**	2,568

Lease terms are negotiated on an individual basis and contain a wide range of different terms and conditions. The Company has variable lease payments related to property taxes for real estate contracts. The Company includes extension options in the calculation of lease liabilities when the Company has the right to extend a lease term at its discretion and is reasonably certain to exercise the extension option. The Company does not have any significant termination options and the residual amounts are not material.

18. JOINT ARRANGEMENTS

A) Joint Operations

Cenovus has a number of joint operations in the Upstream segments. On September 30, 2025, Cenovus divested its entire 50 percent interest in WRB in the U.S. Refining segment, which was a jointly controlled entity with Phillips 66 (see Note 8).

B) Joint Ventures

Husky-CNOOC Madura Limited

The Company holds a 40 percent interest in the jointly-controlled entity HCML. The Company's share of equity investment income (loss) related to the joint venture is recorded in (income) loss from equity-accounted affiliates.

Summarized below is the financial information for HCML accounted for using the equity method.

Results of Operations

For the years ended December 31,	**2025**	2024
Revenue	**646**	736
Expenses	**610**	605
Net Earnings (Loss)	**36**	131

Balance Sheet

As at December 31,	**2025**	2024
Current Assets [(1)]	**270**	441
Non-Current Assets	**1,227**	1,594
Current Liabilities	**82**	188
Non-Current Liabilities	**868**	1,046
Net Assets	**547**	801

(1) Includes cash and cash equivalents of $82 million (December 31, 2024 – $108 million).

For the year ended December 31, 2025, the Company's share of income from the equity-accounted affiliate was $31 million (2024 – $53 million). As at December 31, 2025, the carrying amount of the Company's share of net assets was $202 million (December 31, 2024 – $294 million). These amounts do not equal the 40 percent joint control of the revenues, expenses and net assets of HCML due to differences in the values attributed to the investment and accounting policies between the joint venture and the Company.

For the year ended December 31, 2025, the Company received $94 million in distributions from HCML (2024 – $107 million) and paid $nil in contributions (2024 – $nil).

Other Joint Ventures

The Company has interests in a number of individually immaterial joint ventures, which include HMLP and Duvernay. The Company's aggregate share of equity investment income (loss) related to these joint ventures are recorded in (income) loss from equity-accounted affiliates.

Summarized aggregate financial information is shown below:

For the years ended December 31,	**2025**	2024
Cenovus's Share of Net Earnings (Loss)	**(26)**	(16)
Cenovus's Share of Other Comprehensive Income (Loss)	**—**	(2)
Cenovus's Share of Total Comprehensive Income (Loss)	**(26)**	(18)

The Company's share of equity investment income related to HMLP, in excess of the cumulative unrecognized losses, distributions received and contributions paid, is recorded in (income) loss from equity-accounted affiliates. Cenovus had unrecognized cumulative losses from earnings and OCI, net of tax, of $58 million as at December 31, 2025 (2024 – $48 million) related to HMLP.

For the year ended December 31, 2025, the Company received $40 million in distributions from HMLP (2024 – $65 million) and paid $2 million in contributions (2024 – $51 million).

As at December 31, 2025, the aggregate carrying value of the Company's investment in these joint ventures was $93 million (December 31, 2024 – $105 million).

19. OTHER ASSETS

As at December 31,	**2025**	2024
Private Equity Investments (Note 31)	**193**	219
Precious Metals	**54**	92
Long-Term Receivables and Prepaids	**130**	68
Net Investment in Finance Leases	**64**	61
Intangible Assets	**23**	11
	464	451

20. GOODWILL

	2025	2024
Carrying Value, Beginning of Year	**2,923**	2,923
Goodwill Disposed	**(11)**	—
Carrying Value, End of Year	**2,912**	2,923

The carrying amount of goodwill is allocated to the following CGUs:

As at December 31,	**2025**	2024
Primrose (Foster Creek)	**1,171**	1,171
Christina Lake	**1,101**	1,101
Lloydminster Thermal	**640**	651
	2,912	2,923

21. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

As at December 31,	**2025**	2024
Trade and Accruals	**5,502**	5,907
Joint Operations Payable	**66**	110
Employee Long-Term Incentives	**163**	132
Interest	**80**	72
Provisions for Onerous and Unfavourable Contracts	**26**	11
Other	**10**	10
	5,847	6,242

22. DEBT AND CAPITAL STRUCTURE

For the year ended December 31, 2025, the annualized weighted average interest rate on outstanding debt, including the Company's proportionate share of short-term borrowings, was 4.5 percent (2024 – 4.5 percent).

A) Short-Term Borrowings

As at December 31,	Notes	**2025**	2024
Uncommitted Demand Facilities	i	**—**	—
WRB Uncommitted Demand Facilities	ii	**—**	173
Total Debt Principal		**—**	173

i) Uncommitted Demand Facilities

As at December 31, 2025, the Company had uncommitted demand facilities of $1.5 billion (December 31, 2024 – $1.7 billion) in place, of which $1.4 billion may be drawn for general purposes, or the full amount may be available to issue letters of credit. As at December 31, 2025, there were outstanding letters of credit aggregating to $341 million (December 31, 2024 – $355 million) and no direct borrowings (December 31, 2024 – $nil).

ii) WRB Uncommitted Demand Facilities

On September 30, 2025, Cenovus completed the divestiture of its entire 50 percent interest in WRB, which included the Company's proportionate share of the WRB uncommitted demand facilities outstanding of US$225 million (C$313 million) (see Note 8). Cenovus's proportionate share of the WRB uncommitted demand facilities outstanding as at December 31, 2024, was US$120 million (C$173 million).

B) Long-Term Debt

As at December 31,	Notes	**2025**	2024
Committed Credit Facility	i	**—**	—
Term Loan Facility	ii	**2,700**	—
U.S. Dollar Denominated Senior Unsecured Notes	iii	**5,887**	5,470
Canadian Dollar Senior Unsecured Notes	iii	**2,450**	2,000
Total Debt Principal		**11,037**	7,470
Debt Premiums (Discounts), Net, and Transaction Costs		**(5)**	64
Long-Term Debt		**11,032**	7,534
Less: Current Portion		**—**	192
Long-Term Portion		**11,032**	7,342

i) Committed Credit Facility

On September 19, 2025, Cenovus renewed its existing committed credit facility to extend the maturity dates by more than one year. As at December 31, 2025, the committed credit facility consists of a $3.3 billion tranche maturing on September 19, 2029, and a $2.2 billion tranche maturing on September 19, 2028. As at December 31, 2025, no amount was drawn on the credit facility (December 31, 2024 – $nil).

The committed credit facility may include Canadian Overnight Repo Rate Average ("CORRA") loans, Secured Overnight Financing Rate ("SOFR") loans, prime rate loans and U.S. Base Rate ("USBR") loans.

ii) Term Loan Facility

Cenovus obtained a $2.7 billion term loan facility maturing on February 28, 2029, to fund a portion of the cash consideration for the MEG Acquisition (see Note 4). The term loan facility is unsecured and bears interest at the CORRA, SOFR, prime lending rate or USBR, as selected by the Company, plus the applicable pricing margins, which vary based on the Company's credit rating.

iii) U.S. Dollar Denominated and Canadian Dollar Denominated Senior Unsecured Notes

Upon maturity on July 15, 2025, the Company repaid its 5.38 percent senior unsecured notes with a principal of US$133 million, in full.

Upon closing of the MEG Acquisition, the Company assumed MEG's U.S. dollar senior unsecured notes with a fair value of $843 million (notional value – US$600 million) (see Note 4). The notes were subsequently redeemed on December 1, 2025, in full.

On November 20, 2025, the Company closed public offerings in Canada and the U.S. of senior unsecured notes of $2.6 billion, composed of $650 million 4.25 percent notes due in 2033, $550 million 4.60 percent notes due in 2035, US$500 million 4.65 percent notes due in 2031 and US$500 million 5.40 percent notes due in 2036.

On December 1, 2025, the Company redeemed its 4.25 percent senior unsecured notes with a principal of US$373 million, in full. On December 22, 2025, the Company redeemed its 3.60 percent senior unsecured notes with a principal of $750 million, in full. For the year ended December 31, 2025, a premium on redemption, net of amortization costs, of $9 million was recorded in finance costs.

The principal amounts of the Company's outstanding senior unsecured notes are:

	2025		2024	
As at December 31,	**US$ Principal**	**C$ Principal and Equivalent**	US$ Principal	C$ Principal and Equivalent
U.S. Dollar Denominated Senior Unsecured Notes				
5.38% due July 15, 2025	**—**	**—**	133	192
4.25% due April 15, 2027	**—**	**—**	373	537
4.40% due April 15, 2029	**183**	**250**	183	262
4.65% due March 20, 2031	**500**	**685**	—	—
2.65% due January 15, 2032	**500**	**685**	500	720
5.40% due March 20, 2036	**500**	**685**	—	—
5.25% due June 15, 2037	**333**	**457**	333	479
6.80% due September 15, 2037	**191**	**262**	191	275
6.75% due November 15, 2039	**652**	**894**	652	938
4.45% due September 15, 2042	**91**	**125**	91	131
5.20% due September 15, 2043	**27**	**37**	27	39
5.40% due June 15, 2047	**569**	**779**	569	818
3.75% due February 15, 2052	**750**	**1,028**	750	1,079
	4,296	**5,887**	3,802	5,470
Canadian Dollar Senior Unsecured Notes				
3.60% due March 10, 2027		**—**		750
3.50% due February 7, 2028		**1,250**		1,250
4.25% due March 20, 2033		**650**		—
4.60% due November 20, 2035		**550**		—
		2,450		2,000
Total Senior Unsecured Notes		**8,337**		7,470

As at December 31, 2025, the Company was in compliance with all of the terms of its debt agreements. Under the terms of Cenovus's committed credit facility and term loan facility, the Company is required to maintain a total debt to capitalization ratio, as defined in the agreements, not to exceed 65 percent. The Company is below this limit.

C) Mandatory Debt Payments

	U.S. Dollar Senior Unsecured Notes		Canadian Dollar Senior Unsecured Notes	Term Loan Facility	Total
As at December 31, 2025	US$ Principal	C$ Principal Equivalent	C$ Principal	C$ Principal	C$ Principal and Equivalent
2026	—	—	—	—	—
2027	—	—	—	—	—
2028	—	—	1,250	—	1,250
2029	183	250	—	2,700	2,950
2030	—	—	—	—	—
Thereafter	4,113	5,637	1,200	—	6,837
	4,296	5,887	2,450	2,700	11,037

D) Capital Structure

Cenovus's capital structure consists of shareholders' equity and Net Debt. Net Debt includes the Company's short-term borrowings, and the current and long-term portions of long-term debt, net of cash and cash equivalents, and short-term investments. Net Debt is used in managing the Company's capital structure. The Company's objectives when managing its capital structure are to maintain financial flexibility, preserve access to capital markets, ensure its ability to finance internally generated growth and to fund potential acquisitions, while maintaining the ability to meet the Company's financial obligations as they come due. To ensure financial resilience, Cenovus may, among other actions, adjust capital and operating spending, steward working capital, draw down on its credit facilities or repay existing debt, adjust dividends paid to shareholders, purchase the Company's common shares or preferred shares for cancellation, issue new debt, or issue new shares.

Cenovus monitors its capital structure and financing requirements using, among other things, Total Debt, Net Debt to adjusted earnings before interest, taxes and DD&A ("Adjusted EBITDA"), Net Debt to Adjusted Funds Flow and Net Debt to Capitalization. These measures are used to steward Cenovus's overall debt position as measures of Cenovus's overall financial strength.

Cenovus targets a Net Debt to Adjusted EBITDA ratio and a Net Debt to Adjusted Funds Flow ratio of approximately 1.0 times and Net Debt at or below $4.0 billion over the long-term at a WTI price of US$45.00 per barrel. These measures may fluctuate periodically outside this range due to factors such as persistently high or low commodity prices or the strengthening or weakening of the Canadian dollar relative to the U.S. dollar.

On November 28, 2025, Cenovus filed a base shelf prospectus that allows the Company to offer, from time to time, debt securities, common shares, preferred shares, subscription receipts, warrants, share purchase contracts and units in Canada, the U.S. and elsewhere as permitted by law. The base shelf prospectus will expire in December 2028. Offerings under the base shelf prospectus are subject to market conditions on terms set forth in one or more prospectus supplements.

To provide the Company with additional flexibility in managing liquidity and optimizing working capital, Cenovus leverages uncommitted receivables purchase agreements (the "Receivables Purchase Agreements") with financial institutions, which may be used from time to time as part of the Company's working capital management strategy. The Receivables Purchase Agreements, when utilized, provide the Company with the ability, at its discretion, to sell interests in certain trade and accrued receivables. Transactions under the Receivables Purchase Agreements are structured such that the Company retains ongoing involvement with the receivables, including servicing activities, and continues to reflect the related receivables on its consolidated balance sheets. As at December 31, 2025, there were no transactions executed under the Receivables Purchase Agreements.

Net Debt to Adjusted EBITDA

As at December 31,	**2025**	2024
Short-Term Borrowings	**—**	173
Current Portion of Long-Term Debt	**—**	192
Long-Term Portion of Long-Term Debt	**11,032**	7,342
Total Debt	**11,032**	7,707
Less: Cash and Cash Equivalents	**(2,740)**	(3,093)
Net Debt	**8,292**	4,614
Net Earnings (Loss)	**3,930**	3,142
Add (Deduct):		
Finance Costs, Net	**569**	514
Income Tax Expense (Recovery)	**547**	929
Depreciation, Depletion and Amortization	**5,192**	4,871
Exploration and Evaluation Asset Write-downs	**25**	37
(Income) Loss From Equity-Accounted Affiliates	**(53)**	(66)
Unrealized (Gain) Loss on Risk Management	**(15)**	12
Foreign Exchange (Gain) Loss, Net	**(361)**	462
(Gain) Loss on Divestiture of Assets	**(87)**	(119)
Re-measurement of Contingent Payments	**—**	30
Other (Income) Loss, Net	**(115)**	(55)
Adjusted EBITDA [(1)]	**9,632**	9,757
Net Debt to Adjusted EBITDA (times)	**0.9**	0.5

(1) Calculated on a trailing twelve-month basis.

Net Debt to Adjusted Funds Flow

As at December 31,	**2025**	2024
Net Debt	**8,292**	4,614
Cash From (Used in) Operating Activities	**8,228**	9,235
(Add) Deduct:		
Settlement of Decommissioning Liabilities	**(280)**	(234)
Net Change in Non-Cash Working Capital	**(363)**	1,305
Adjusted Funds Flow [(1)]	**8,871**	8,164
Net Debt to Adjusted Funds Flow (times)	**0.9**	0.6

(1) Calculated on a trailing twelve-month basis.

Net Debt to Capitalization

As at December 31,	**2025**	2024
Net Debt	**8,292**	4,614
Shareholders' Equity	**31,622**	29,754
Capitalization	**39,914**	34,368
Net Debt to Capitalization (percent)	**21**	13

23. DECOMMISSIONING LIABILITIES

	2025	2024
Decommissioning Liabilities, Beginning of Year	**4,534**	4,155
Liabilities Acquired (Note 4)	**267**	—
Liabilities Incurred	**269**	24
Liabilities Settled	**(280)**	(234)
Change in Estimated Future Cash Flows	**54**	276
Change in Discount Rates	**(143)**	132
Unwinding of Discount on Decommissioning Liabilities (Note 6)	**243**	225
Liabilities Disposed (Note 8)	**(61)**	(72)
Exchange Rate Movements and Other	**(11)**	28
Decommissioning Liabilities, End of Year	**4,872**	4,534

As at December 31, 2025, the undiscounted amount of estimated future cash flows required to settle the obligation is $17.7 billion (December 31, 2024 – $15.6 billion). Most of these obligations are not expected to be paid for several years, or decades, and will be funded through general resources when they become due. The Company plans to settle approximately $222 million of decommissioning liabilities over the next year. Revisions in estimated future cash flows resulted from a change in the timing of decommissioning liabilities over the estimated life of the reserves and an increase in cost estimates. These obligations were discounted using a credit-adjusted risk-free rate of 5.5 percent (December 31, 2024 – 5.2 percent) and assumes an inflation rate of two percent (December 31, 2024 – two percent).

The Company deposits cash into restricted accounts that will be used to fund decommissioning liabilities in offshore China in accordance with the provisions of the regulations of the People's Republic of China. As at December 31, 2025, the Company had $256 million in long-term restricted cash (December 31, 2024 – $241 million).

Sensitivities

Changes to the credit-adjusted risk-free rate or the inflation rate would have the following impact on the decommissioning liabilities:

	Sensitivity	**2025**		2024	
As at December 31,	**Range**	**Increase**	**Decrease**	Increase	Decrease
Credit-Adjusted Risk-Free Rate	± one percent	**(548)**	**669**	(487)	595
Inflation Rate	± one percent	**685**	**(567)**	615	(507)

24. OTHER LIABILITIES

As at December 31,	**2025**	2024
Renewable Volume Obligation, Net [(1)]	**235**	284
Pension and Other Post-Employment Benefit Plan	**260**	269
Employee Long-Term Incentives	**169**	96
Provisions for Onerous and Unfavourable Contracts	**83**	66
Provision for West White Rose Expansion Project	**—**	54
Other	**142**	150
	889	919

(1) The gross amounts of the renewable volume obligation ("RVO") and RINs asset were $853 million and $618 million, respectively (December 31, 2024 – $652 million and $368 million, respectively).

25. PENSIONS AND OTHER POST-EMPLOYMENT BENEFITS

The Company provides the majority of employees with a defined contribution pension plan ("DC Pension Plan"). The Company also provides other post-employment benefit ("OPEB") plans to retirees and sponsors defined benefit pension plans in Canada and the U.S. (together, the "DB Pension Plan").

The DB Pension Plan provides pension benefits at retirement based on years of service and final average earnings. In Canada, future enrollment is limited to a small group of eligible employees who may elect to move from the defined contribution component to the defined benefit component for their future service. In the U.S., the defined benefit pension is closed to new members. The Company's OPEB plans provides certain retired employees with health care and dental benefits.

The Company is required to file actuarial valuations of its registered defined benefit pension plans with regulators on a periodic basis. The most recently filed valuation for the Canadian defined benefit pension plan was dated December 31, 2023, and the next required actuarial valuation will be as at December 31, 2026. The most recently filed valuation for the U.S. defined benefit pension plan was dated January 1, 2025, and the next required actuarial valuation was dated January 1, 2026.

A) Plan Obligations, Assets and Funded Status

	DB Pension Plan		OPEB Plans	
	2025	2024	**2025**	2024
Defined Benefit Obligation				
Defined Benefit Obligation, Beginning of Year	**214**	202	**252**	249
Current Service Costs	**16**	14	**7**	2
Interest Costs [1]	**10**	9	**12**	12
Benefits Paid	**(13)**	(12)	**(8)**	(9)
Plan Participant Contributions	**3**	3	**—**	—
Re-measurements:				
(Gains) Losses From Experience Adjustments	**(1)**	—	**(3)**	1
(Gains) Losses From Changes in Financial Assumptions	**(5)**	(3)	**(2)**	(6)
Exchange Rate Movements and Other	**(1)**	1	**(2)**	3
Defined Benefit Obligation, End of Year	**223**	214	**256**	252
Plan Assets				
Fair Value of Plan Assets, Beginning of Year	**201**	178	**—**	—
Employer Contributions	**12**	11	**8**	9
Plan Participant Contributions	**3**	3	**—**	—
Benefits Paid	**(13)**	(12)	**(8)**	(9)
Interest Income [1]	**10**	8	**—**	—
Re-measurements:				
Return on Plan Assets Excluding Interest Income	**11**	11	**—**	—
Exchange Rate Movements and Other	**(1)**	2	**—**	—
Fair Value of Plan Assets, End of Year	**223**	201	**—**	—
Defined Benefit Pension and OPEB Asset (Liability) [2]	**—**	(13)	**(256)**	(252)

(1) Based on the discount rate of the defined benefit obligation at the beginning of the year.
(2) Liabilities for the DB Pension Plan and OPEB plans are included in other liabilities.

The weighted average duration of the obligations for the DB Pension Plan and OPEB plans are 15 years and 13 years, respectively.

B) Costs

For the years ended December 31,	DB Pension Plan and DC Pension Plan		OPEB Plans	
	2025	2024	**2025**	2024
Defined Benefit Plan Cost				
Current Service Costs	**16**	14	**7**	2
Net Interest Costs	**—**	1	**12**	12
Re-measurements:				
Return on Plan Assets Excluding Interest Income	**(11)**	(11)	**—**	—
(Gains) Losses From Experience Adjustments	**(1)**	—	**(3)**	1
(Gains) Losses From Changes in Financial Assumptions	**(5)**	(3)	**(2)**	(6)
Defined Benefit Plan Cost (Recovery)	**(1)**	1	**14**	9
Defined Contribution Plan Cost [(1)]	**113**	107	**—**	—
Total Plan Cost	**112**	108	**14**	9

(1) Includes defined contribution and U.S. 401(k) plans.

C) Investment Objectives and Fair Value of Plan Assets

The objective of the asset allocation is to manage the funded status of the DB Pension Plan at an appropriate level of risk, giving consideration to the security of the assets and the potential volatility of market returns, and the resulting effect on both contribution requirements and pension expense. The long-term return is expected to achieve or exceed the return from a composite benchmark composed of passive investments in appropriate market indices. The asset allocation structure is subject to diversification requirements and constraints that reduce risk by limiting exposure to individual equity investment and credit rating categories.

The allocation of assets between the various types of investment funds is monitored regularly and is re-balanced as necessary. The Canadian defined benefit pension plan and U.S. defined benefit pension plan are managed independently of each other and, accordingly, the target asset allocation is reflective of their different liability profiles. The Company does not use derivative instruments to manage the risks of its plan assets. There has been no change in the process used by the Company to manage these risks from prior periods.

The fair value of the DB Pension Plan assets, as represented by fair value hierarchy levels, are as follows:

As at December 31,	**2025**	2024
Level 1 – Cash and Cash Equivalents	**4**	3
Level 2 – Equity and Fixed Income Funds	**206**	185
Level 3 – Real Estate Funds and Other	**13**	13
	223	201

The DB Pension Plan does not hold any direct investment in Cenovus common shares or preferred shares.

D) Funding

The DB Pension Plan is funded in accordance with applicable pension legislation. Contributions are made to trust funds administered by independent trustees. The Company's contributions to the DB Pension Plan are based on the most recent actuarial valuations and the direction of the Management Pension Committees and Human Resources and Compensation Committee of the Board of Directors.

Employees participating in the Canadian defined benefit pension are required to contribute four percent of their pensionable earnings, up to an annual maximum, and the Company provides the balance of the funding necessary to ensure benefits will be fully provided for at retirement. In the year ended December 31, 2026, the Company expects to contribute $12 million to the DB Pension Plan.

The OPEB plans are funded on an as required basis. For the year ended December 31, 2026, the Company expects to contribute $12 million to the OPEB plans.

E) Actuarial Assumptions and Sensitivities

Actuarial Assumptions

The principal weighted average actuarial assumptions used to determine benefit obligations are as follows:

	Defined Benefit Plan		OPEB Plans	
For the years ended December 31,	**2025**	2024	**2025**	2024
Discount Rate (percent)	**4.93**	4.65	**5.02**	4.85
Future Salary Growth Rate (percent)	**3.94**	3.95	**N/A**	N/A
Average Longevity (years)	**88.5**	88.4	**88.5**	88.4
Health Care Cost Trend Rate (percent)	**N/A**	N/A	**5.45**	5.24

Discount rates are based on market yields for high quality corporate debt instruments with maturity terms equivalent to the benefit obligations.

Sensitivities

The sensitivity of the DB Pension Plan and OPEB plan obligations to a one percent change in future salary growth rate, health care cost trend rate, or a one year change in assumed life expectancy is nominal. The sensitivity analysis below shows the impact that a one percent change in the discount rate, while holding all other assumptions constant, would have on the DP Pension Plan and OPEB plan obligations:

	2025		2024	
As at December 31,	**Increase**	**Decrease**	Increase	Decrease
Discount Rate	**(57)**	**69**	(56)	69

Actual experience may result in a number of assumptions changing simultaneously, and the changes in some assumptions may be correlated. When calculating the sensitivity of the DB Pension Plan and the OPEB plan obligations to significant actuarial assumptions, the same methodologies have been applied as when valuing the obligations to be recognized on the Consolidated Balance Sheets.

26. SHARE CAPITAL AND WARRANTS

A) Authorized

Cenovus is authorized to issue an unlimited number of common shares, and first and second preferred shares not exceeding, in aggregate, 20 percent of the number of issued and outstanding common shares. The first and second preferred shares may be issued in one or more series with rights and conditions to be determined by the Board of Directors prior to issuance and subject to the Company's articles.

B) Issued and Outstanding – Common Shares

	2025		2024	
	Number of Common Shares (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**1,825,038**	**15,659**	1,871,868	16,031
Issued Under the MEG Acquisition, Net of Issuance Costs (Note 4)	**143,935**	**3,667**	—	—
Issued Upon Exercise of Warrants	**2,471**	**24**	3,982	39
Issued Under Stock Option Plans	**1,394**	**20**	5,049	68
Purchase of Common Shares under NCIB	**(89,438)**	**(771)**	(55,861)	(479)
Outstanding, End of Year	**1,883,400**	**18,599**	1,825,038	15,659

As at December 31, 2025, there were 24.9 million common shares available for future issuance under the stock option plan.

C) Normal Course Issuer Bid

For the year ended December 31, 2025, the Company purchased and cancelled 89.4 million common shares (2024 – 55.9 million) through the NCIB. The shares were purchased at a volume weighted average price of $21.87 per common share (2024 – $25.38) for a total of $2.0 billion (2024 – $1.4 billion). Paid in surplus representing the retained earnings prior to the split with Encana Corporation, now known as Ovintiv Inc. ("Ovintiv"), was reduced in full by $541 million. Retained earnings was then reduced by $683 million. The cumulative reduction to paid in surplus and retained earnings was $1.2 billion, which relates to the excess of the purchase price of the common shares over their average carrying value and share buyback tax of $38 million.

For the year ended December 31, 2024, paid in surplus was reduced by $966 million, representing the excess of the purchase price of the common shares over their average carrying value of $939 million and share buyback tax of $27 million.

On November 7, 2025, the Company received approval from the TSX to renew the Company's NCIB program to purchase up to 120.3 million common shares during the period from November 11, 2025, to November 10, 2026.

From January 1, 2026, to February 13, 2026, the Company purchased an additional 5.0 million common shares for $126 million. As at February 13, 2026, the Company can further purchase up to 107.9 million common shares under the NCIB.

D) Treasury Shares

Cenovus has an employee benefit plan trust (the "Trust"). The Trust, through an independent trustee, acquires Cenovus's common shares on the open market, which are held to satisfy the Company's obligations under certain stock-based compensation plans.

	2025		2024	
	Number of Common Shares (thousands)	**Amount**	Number of Common Shares (thousands)	Amount
Outstanding, Beginning of Year	**2,000**	**43**	—	—
Purchase of Common Shares Under Employee Benefit Plan	**7,100**	**155**	2,000	43
Distributed Under Employee Benefit Plan	**(3,842)**	**(82)**	—	—
Outstanding, End of Year	**5,258**	**116**	2,000	43

Paid in surplus was reduced by $6 million, representing the difference between the long-term incentive obligation and the weighted average carrying value of the treasury shares on settlement.

E) Issued and Outstanding – Preferred Shares

First Preferred Shares

	2025		2024	
	Number of Preferred Shares (thousands)	**Amount**	Number of Preferred Shares (thousands)	Amount
Outstanding, Beginning of Year	**26,000**	**356**	36,000	519
Preferred Shares Redeemed	**(14,000)**	**(243)**	(10,000)	(163)
Outstanding, End of Year	**12,000**	**113**	26,000	356

On March 31, 2025, and June 30, 2025, Cenovus exercised its right to redeem all 8.0 million of the Company's series 5 preferred shares and all 6.0 million of the Company's series 7 preferred shares, respectively. The preferred shares were redeemed at a price of $25.00 per share for a total of $350 million. Paid in surplus was reduced by $107 million, representing the excess of the purchase price of the preferred shares over their carrying value.

On December 31, 2024, Cenovus exercised its right to redeem all 10.0 million of the Company's series 3 preferred shares at a price of $25.00 per share for a total of $250 million. Paid in surplus was reduced by $87 million, representing the excess of the purchase price of the series 3 preferred shares over their carrying value.

The Company had the following preferred shares outstanding as at December 31, 2025:

As at December 31, 2025	Dividend Reset Date	Dividend Rate (percent)	Number of Preferred Shares (thousands)
Series 1 First Preferred Shares	**March 31, 2026**	**2.58**	**10,740**
Series 2 First Preferred Shares [(1)]	**Quarterly**	**3.95**	**1,260**

(1) The floating-rate dividend was 5.21 percent from December 31, 2024, to March 30, 2025 (December 31, 2023, to March 30, 2024 – 6.77 percent); 4.57 percent from March 31, 2025, to June 29, 2025 (March 31, 2024, to June 29, 2024 – 6.71 percent); 4.37 percent from June 30, 2025, to September 29, 2025 (June 30, 2024, to September 29, 2024 – 6.60 percent); and 4.39 percent from September 30, 2025, to December 30, 2025 (September 30, 2024, to December 30, 2024 – 5.94 percent).

Every five years, subject to certain conditions, the holders of first preferred shares will have the right, at their option, to convert their shares into a specified series of first preferred shares should the Company elect to not redeem the shares. On March 31, 2026, and on March 31 every five years thereafter, holders of series 1 and series 2 first preferred shares will have such option to convert their shares into the other series.

Each series of outstanding first preferred shares are entitled to receive a cumulative quarterly dividend, payable on the last day of March, June, September and December in each year, if, as and when declared by Cenovus's Board of Directors. For the series 1 first preferred shares, such dividend rate resets every five years at the rate equal to the sum of the five-year Government of Canada bond yield on the applicable calculation date plus 1.73 percent. For the series 2 first preferred shares, such dividend rate resets every quarter at the rate equal to the sum of the 90-day Government of Canada Treasury Bill yield on the applicable calculation date plus 1.73 percent.

Every five years, subject to certain conditions, on the applicable conversion date Cenovus may, at its option, redeem all or any number of the then-outstanding series of first preferred shares by payment of an amount in cash for each share to be redeemed equal to $25.00. In addition, subject to certain conditions, on any other date Cenovus may, at its option, redeem all or any number of the then-outstanding series 2 first preferred shares, by payment of an amount in cash for each share to be redeemed equal to $25.50. In each case, such payment shall also include all accrued and unpaid dividends thereon to but excluding the date fixed for redemption (less any tax or other amount required to be deducted and withheld).

If a dividend on any preferred share is not paid in full on any dividend payment date, then a dividend restriction on the common shares shall apply. The preferred share dividends are cumulative.

Second Preferred Shares

There were no second preferred shares outstanding as at December 31, 2025 (December 31, 2024 – nil).

F) Issued and Outstanding – Warrants

	2025		2024	
	Number of Warrants (thousands)	**Amount**	Number of Warrants (thousands)	Amount
Outstanding, Beginning of Year	**3,643**	**12**	7,625	25
Exercised	**(2,471)**	**(8)**	(3,982)	(13)
Outstanding, End of Year	**1,172**	**4**	3,643	12

The exercise price of the warrants was $6.54 per share. The warrants expired on January 1, 2026.

G) Paid in Surplus

	Retained Earnings Prior to Ovintiv Split	Stock-Based Compensation	Total
As at December 31, 2023	1,707	295	2,002
Common Shares Issued on Exercise of Stock Options	—	(16)	(16)
Purchase of Common Shares Under NCIB	(966)	—	(966)
Preferred Shares Redeemed	(87)	—	(87)
Stock-Based Compensation Expense	—	11	11
As at December 31, 2024	**654**	**290**	**944**
Common Shares Issued on Exercise of Stock Options	**—**	**(4)**	**(4)**
Purchase of Common Shares Under NCIB	**(541)**	**—**	**(541)**
Common Shares Issued Under Employee Benefit Plan	**(6)**	**—**	**(6)**
Preferred Shares Redeemed	**(107)**	**—**	**(107)**
Stock-Based Compensation Expense	**—**	**12**	**12**
As at December 31, 2025	**—**	**298**	**298**

27. ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

	Pension and Other Post-Retirement Benefits	Private Equity Instruments	Foreign Currency Translation Adjustment	Total
As at December 31, 2023	55	85	1,068	1,208
Other Comprehensive Income (Loss), Before Tax	19	81	1,020	1,120
Income Tax (Expense) Recovery	(5)	(10)	—	(15)
As at December 31, 2024	**69**	**156**	**2,088**	**2,313**
Other Comprehensive Income (Loss), Before Tax	**22**	**(27)**	**(643)**	**(648)**
Reclassification on Divestiture (Note 8)	**—**	**—**	**(1,261)**	**(1,261)**
Income Tax (Expense) Recovery	**(5)**	**2**	**—**	**(3)**
As at December 31, 2025	**86**	**131**	**184**	**401**

28. STOCK-BASED COMPENSATION PLANS

Cenovus has a number of stock-based compensation plans that include net settlement rights (“NSRs”), performance share units (“PSUs”), restricted share units (“RSUs”) and deferred share units (“DSUs”).

A) Employee Stock Options

Cenovus has an Employee Stock Option Plan that provides employees with the opportunity to exercise an option to purchase a common share of the Company. Option exercise prices approximate the market value for the common shares on the date the options were issued. Options granted are exercisable at 30 percent of the number granted after one year, an additional 30 percent of the number granted after two years and are fully exercisable after three years. Options expire after seven years.

Options issued by the Company have associated NSRs. The NSR, in lieu of exercising the option, gives the option holder the right to receive the number of common shares that could be acquired with the excess value of the market price of Cenovus's common shares at the time of exercise over the exercise price of the option. Alternatively, the holder may elect to exercise the option and receive a net cash payment equal to the excess of the market price received from the sale of the common shares over the exercise price of the option.

The NSRs vest and expire under the same terms and conditions of the underlying option.

Stock Options With Associated Net Settlement Rights

The weighted average unit fair value of NSRs granted during the year ended December 31, 2025, was $2.64 before considering forfeitures, which are considered in determining total cost for the period. The fair value of each NSR was estimated on its grant date using the Black-Scholes-Merton valuation model with weighted average assumptions as follows:

Risk-Free Interest Rate (percent)	**2.61**
Expected Dividend Yield (percent)	**3.60**
Expected Volatility [1] (percent)	**20.65**
Expected Life (years)	**5.30**

(1) Expected volatility has been based on historical share volatility of the Company.

For the year ended December 31, 2025, 328 thousand NSRs, with a weighted average exercise price of $9.48, were exercised and settled for 328 thousand common shares.

For the year ended December 31, 2025	Number of Stock Options with Associated Net Settlement Rights (thousands)	Weighted Average Exercise Price ($/unit)
Outstanding, Beginning of Year	**8,653**	**17.83**
Granted	**4,389**	**20.42**
Exercised	**(1,384)**	**11.70**
Forfeited	**(568)**	**20.77**
Expired	**(228)**	**22.99**
Outstanding, End of Year	**10,862**	**19.40**

	Outstanding			Exercisable	
As at December 31, 2025 **Range of Exercise Price** ($/unit)	Number of Stock Options with Associated Net Settlement Rights (thousands)	Weighted Average Remaining Contractual Life (years)	Weighted Average Exercise Price ($/unit)	Number of Stock Options with Associated Net Settlement Rights (thousands)	Weighted Average Exercise Price ($/unit)
5.00 to 9.99	**916**	**2.14**	**8.69**	**916**	**8.69**
10.00 to 14.99	**1,246**	**0.93**	**11.69**	**1,246**	**11.69**
15.00 to 19.99	**1,398**	**3.19**	**19.86**	**1,376**	**19.88**
20.00 to 24.99	**7,083**	**5.58**	**21.81**	**1,279**	**23.86**
25.00 to 29.99	**219**	**5.49**	**27.18**	**66**	**27.18**
	10,862	**4.45**	**19.40**	**4,883**	**16.83**

Cenovus Replacement Stock Options

For the year ended December 31, 2025, 317 thousand Cenovus replacement stock options with a weighted average exercise price of $3.54 were exercised and net settled for cash, and 12 thousand Cenovus replacement stock options were exercised with a weighted average price of $3.54 and settled for 10 thousand common shares.

As at December 31, 2025, no Cenovus replacement stock options were outstanding.

B) Performance Share Units

Cenovus granted PSUs to certain employees under its Performance Share Unit Plan for Employees. The PSUs are time-vested whole-share units that entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. PSUs granted under the Performance Share Unit Plan for Local Employees in the Asia Pacific region may only be settled in cash.

The number of PSUs eligible to vest is determined by a multiplier that ranges from zero percent to 200 percent and is based on the Company achieving key pre-determined performance measures. PSUs vest after three years.

The Company has recorded a liability of $128 million as at December 31, 2025, (December 31, 2024 – $80 million) for PSUs based on the market value of Cenovus's common shares at the end of the year. PSUs are paid out upon vesting and, as a result, the intrinsic value was $nil as at December 31, 2025.

For the year ended December 31, 2025	Number of Performance Share Units (thousands)
Outstanding, Beginning of Year	**7,210**
Granted	**3,365**
Vested and Paid Out	**(2,305)**
Forfeited	**(1,016)**
Units Granted in Lieu of Base Dividends	**275**
Outstanding, End of Year	**7,529**

C) Restricted Share Units

Cenovus granted RSUs to certain employees under its Restricted Share Unit Plan for Employees. RSUs are whole-share units and entitle employees to receive, upon vesting, either a common share of Cenovus or a cash payment equal to the value of a Cenovus common share. RSUs vest over three years. RSUs granted under the Restricted Share Unit Plan for Local Employees in the Asia Pacific region may only be settled in cash.

In connection with the MEG Acquisition, the Company assumed all outstanding MEG restricted share awards that were not accelerated at closing. The MEG restricted share awards continue to be governed by and are subject to the terms and conditions of the corresponding legacy MEG plans, which were assumed by Cenovus. No additional share awards will be granted under the legacy MEG plans. As at December 31, 2025, 1,748 thousand restricted share units were outstanding under the legacy MEG plans.

The Company recorded a liability of $161 million as at December 31, 2025, (December 31, 2024 – $105 million) for RSUs based on the market value of Cenovus's common shares at the end of the year. As RSUs are paid out upon vesting, the intrinsic value of vested RSUs was $nil as at December 31, 2025.

For the year ended December 31, 2025	Number of Restricted Share Units (thousands)
Outstanding, Beginning of Year	**8,148**
Granted	**4,358**
Assumed Pursuant to the MEG Acquisition (Note 4)	**2,630**
Vested and Paid Out	**(2,828)**
Forfeited	**(928)**
Units Granted in Lieu of Base Dividends	**383**
Outstanding, End of Year	**11,763**

D) Deferred Share Units

Under two Deferred Share Unit Plans, Cenovus directors, officers and certain employees may receive DSUs, which are equivalent in value to a common share of the Company. Eligible employees have the option to convert either zero, 25, 50, 75 or 100 percent of their annual bonus award into DSUs. DSUs vest immediately, are settled in cash and are redeemed in accordance with the terms of the agreement and expire on December 15 of the calendar year following the year of cessation of directorship or employment.

The Company recorded a liability of $43 million as at December 31, 2025 (December 31, 2024 – $38 million) for DSUs based on the market value of Cenovus's common shares at the end of the year. The intrinsic value of vested DSUs equals the carrying value as DSUs vest at the time of grant.

For the year ended December 31, 2025	Number of Deferred Share Units (thousands)
Outstanding, Beginning of Year	**1,761**
Granted to Directors	**186**
Granted	**187**
Units Granted in Lieu of Base Dividends	**71**
Redeemed	**(371)**
Outstanding, End of Year	**1,834**

E) Total Stock-Based Compensation

For the years ended December 31,	**2025**	2024
Stock Options With Associated Net Settlement Rights	**10**	12
Cenovus Replacement Stock Options	**(1)**	1
Performance Share Units	**96**	48
Restricted Share Units	**76**	60
Deferred Share Units	**10**	5
Total Stock-Based Compensation Expense (Recovery)	**191**	126

29. EMPLOYEE SALARIES AND BENEFIT EXPENSES

For the years ended December 31,	**2025**	2024
Salaries, Bonuses and Other Short-Term Employee Benefits	**1,541**	1,526
Pension and Post-Employment Benefits	**130**	119
Stock-Based Compensation (Note 28)	**191**	126
Termination Benefits	**110**	41
	1,972	1,812

30. RELATED PARTY TRANSACTIONS

A) Key Management Compensation

Key management includes Directors (executive and non-executive), Executive Officers, Senior Vice-Presidents and Vice-Presidents. The compensation paid or payable to key management is:

For the years ended December 31,	**2025**	2024
Salaries, Director Fees and Other Short-Term Benefits	**44**	47
Pension and Post-Employment Benefits	**3**	4
Stock-Based Compensation	**60**	48
Termination Benefits	**11**	11
	118	110

B) Other Related Party Transactions

The Company charges HMLP for construction and management services, and incurs costs for the use of HMLP's pipeline systems, as well as transportation and storage services. Access fees and transportation and storage services are based on contractually agreed rates with HMLP.

The following table summarizes revenues and associated expenses related to HMLP:

For the years ended December 31,	**2025**	2024
Revenues from Construction and Management Services	**164**	155
Transportation Expenses	**258**	278

31. FINANCIAL INSTRUMENTS

A) Fair Value of Non-Derivative Financial Instruments

The fair values of cash and cash equivalents, accounts receivable and accrued revenues, accounts payable and accrued liabilities, and short-term borrowings approximate their carrying amount due to the short-term maturity of these instruments.

The fair values of restricted cash, certain portions of other assets and certain portions of other liabilities approximate their carrying amount due to the specific non-tradeable nature of these instruments.

Long-term debt is carried at amortized cost. The estimated fair value of long-term debt was determined based on period-end trading prices of long-term debt on the secondary market (Level 2). As at December 31, 2025, the carrying value of Cenovus's long-term debt was $11.0 billion and the fair value was $10.6 billion (December 31, 2024 carrying value – $7.5 billion, fair value – $6.9 billion).

The Company classifies certain private equity investments as FVOCI as they are not held for trading and fair value changes are not reflective of the Company's operations. These assets are carried at fair value in other assets. Fair value is determined based on recent market activity which may include equity transactions of the entity when available (Level 3).

The following table provides a reconciliation of changes in the fair value of private equity investments classified as FVOCI:

	2025	2024
Fair Value, Beginning of Year	**219**	131
Acquisitions	**6**	7
Transfer to Investments in Equity-Accounted Affiliates	**(5)**	—
Changes in Fair Value	**(27)**	81
Fair Value, End of Year	**193**	219

B) Fair Value of Risk Management Assets and Liabilities

Risk management assets and liabilities are carried at fair value in accounts receivable and accrued revenues, accounts payable and accrued liabilities (for short-term positions), and other assets and other liabilities (for long-term positions). Changes in fair value are recorded in (gain) loss on risk management.

The Company's risk management assets and liabilities consist of condensate and refined product futures; crude oil and natural gas futures and swaps; and renewable power, power and foreign exchange contracts. The Company may also enter into forwards and options to manage commodity, foreign exchange and interest rate exposures.

Crude oil, natural gas, condensate, refined products and power contracts are recorded at their estimated fair value based on the difference between the contracted price and the period-end forward price for the same commodity, using quoted market prices or the period-end forward price for the same commodity, extrapolated to the end of the term of the contract (Level 2). The fair value of foreign exchange rate contracts is calculated using external valuation models that incorporate observable market data and foreign exchange forward curves (Level 2).

The fair value of renewable power contracts is calculated using internal valuation models that incorporate broker pricing for relevant markets, some observable market prices and extrapolated market prices with inflation assumptions (Level 3). The fair value of renewable power contracts are calculated by Cenovus's internal valuation team, which consists of individuals who are knowledgeable and have experience in fair value techniques.

Summary of Risk Management Positions

	2025			2024		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Crude Oil, Condensate, Natural Gas and Refined Products	**27**	**30**	**(3)**	9	10	(1)
Power Contracts	**2**	**—**	**2**	6	—	6
Renewable Power Contracts	**17**	**6**	**11**	5	—	5
Foreign Exchange Rate Contracts	**—**	**—**	**—**	—	3	(3)
	46	**36**	**10**	20	13	7

The following table presents the Company's fair value hierarchy for risk management assets and liabilities carried at fair value:

As at December 31,	**2025**	2024
Level 2 – Prices Sourced From Observable Data or Market Corroboration	**(1)**	2
Level 3 – Prices Sourced From Partially Unobservable Data	**11**	5
	10	7

The following table provides a reconciliation of changes in the fair value of Cenovus's risk management assets and liabilities:

	2025	2024
Fair Value of Contracts, Beginning of Year	**7**	12
Change in Fair Value of Contracts in Place at Beginning of Year	**2**	(20)
Change in Fair Value of Contracts Entered Into During the Year	**23**	(30)
Fair Value of Contracts Realized During the Year	**(22)**	46
Unrealized Foreign Exchange Gain (Loss) on U.S. Dollar Contracts	**—**	(1)
Fair Value of Contracts, End of Year	**10**	7

Offsetting Financial Assets and Liabilities

Cenovus offsets risk management assets and liabilities when the counterparty, currency and timing of settlement are the same.

	2025			2024		
	Risk Management			Risk Management		
As at December 31,	**Asset**	**Liability**	**Net**	Asset	Liability	Net
Recognized Risk Management Positions						
Gross Amount	**80**	**70**	**10**	38	31	7
Amount Offset	**(34)**	**(34)**	**—**	(18)	(18)	—
Net Amount	**46**	**36**	**10**	20	13	7

The derivative liabilities do not have credit risk-related contingent features. Due to credit practices that limit transactions according to counterparties' credit quality, the change in fair value through profit or loss attributable to changes in the credit risk of financial liabilities is immaterial.

Cenovus pledges cash collateral with respect to certain of these risk management contracts, which is not offset against the related financial liability. The amount of cash collateral required will vary daily over the life of these risk management contracts as commodity prices change. As at December 31, 2025, $26 million was pledged as cash collateral (December 31, 2024 – $18 million).

C) Earnings Impact of (Gains) Losses From Risk Management Positions

For the years ended December 31,	**2025**	2024
Realized (Gain) Loss	**(22)**	46
Unrealized (Gain) Loss	**(15)**	12
(Gain) Loss on Risk Management	**(37)**	58

Realized and unrealized gains and losses on risk management are recorded in the reportable segment to which the derivative instrument relates.

D) Fair Value of Contingent Payments

The variable payment (Level 3) associated with the transaction with BP Canada Energy Group ULC to purchase the remaining 50 percent interest in Sunrise Oil Sands Partnership ended on August 31, 2024.

	2024
Contingent Payments, Beginning of Year	164
Liabilities Settled or Payable	(194)
Re-measurement	30
Contingent Payments, End of Year	—

32. RISK MANAGEMENT

Cenovus is exposed to financial risks, including market risk related to commodity prices, foreign exchange rates, interest rates and commodity power prices, as well as credit risk and liquidity risk.

To manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus, the Company may periodically enter into financial positions as a part of ongoing operations to market the Company's production and physical inventory positions of crude oil, natural gas, condensate, refined products and power consumption. The Company may also enter into arrangements, such as renewable power contracts or power swaps, to manage exposure to future carbon compliance costs, power prices, energy costs associated with the production, transportation and refining of crude oil, or to offset select carbon emissions.

To manage exposure to interest rate volatility and interest costs on short-term borrowings, the Company may enter into interest rate swap contracts. To mitigate the Company's exposure to foreign exchange rate fluctuations, the Company periodically enters into foreign exchange contracts.

As at December 31, 2025, the fair value of risk management positions was a net asset of $10 million (see Note 31). As at December 31, 2025, there were no foreign exchange contracts or interest rate contracts outstanding. As at December 31, 2024, there were foreign exchange contracts with a notional value of US$250 million and no interest rate contracts outstanding.

Net Fair Value of Risk Management Positions

As at December 31, 2025	Notional Volumes [1] [2]	Terms	Weighted Average Price [2]	Fair Value Asset (Liability)
WTI Contracts Related to Blending [3]				
WTI Fixed – Sell	**9.3 MMbbls**	**January 2026 - December 2026**	**US$59.15/bbl**	**25**
WTI Fixed – Buy	**0.7 MMbbls**	**January 2026 - December 2026**	**US$60.14/bbl**	**(3)**
Power Contacts				**2**
Renewable Power Contracts				**11**
Other Financial Positions [4]				**(25)**
Total Fair Value				**10**

(1) Million barrels ("MMbbls").
(2) Notional volumes and weighted average price are based on multiple contracts of varying amounts and terms over the respective time period; therefore, the notional volumes and weighted average price may fluctuate from month to month.
(3) WTI futures contracts are used to help manage price exposure to condensate used for blending. Includes individual WTI contracts with varying terms, the longest of which is 12 months.
(4) Includes risk management positions related to WCS, heavy oil, light oil and condensate differentials, benchmark delivery location spreads, Belvieu and heating oil fixed price contracts, natural gas basis and fixed price contracts, and reformulated blendstock for oxygenate blending gasoline contracts.

A) Commodity Price and Foreign Exchange Rate Risk

i) Commodity Price Risk

Commodity price risk arises from the effect that fluctuations of forward commodity prices may have on the fair value or future cash flows of financial assets and liabilities. To partially mitigate exposure to commodity price risk, the Company has entered into various financial derivative instruments.

The use of these derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors.

The Company has used crude oil, condensate, refined product, power and natural gas risk management contracts, and swaps, and may enter into options or forwards. In addition, various crude oil, natural gas and condensate basis contracts for both price and location may be used. These derivative instruments are used to partially mitigate exposure to the commodity price risk on its crude oil and condensate transactions and to protect both near-term and future cash flows. Cenovus has entered into a number of transactions to help protect against widening light/heavy crude oil price differentials and to manage exposure to commodity price movements between when products are produced or purchased and when sold to the customer or used by Cenovus. In addition, the Company has entered into risk management positions to help mitigate the risk to incremental margin expected to be received in future periods at the time products will be sold. The Company has used commodity futures and swaps, as well as differential price risk management contracts to partially mitigate its exposure to the commodity price risk on its condensate transactions. Natural gas fixed price and basis instruments are used to partially mitigate its natural gas commodity price risk.

ii) Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of Cenovus's financial assets or liabilities. As Cenovus operates in North America, fluctuations in the exchange rate between the U.S./Canadian dollar can have a significant effect on reported results.

Cenovus's foreign exchange (gain) loss primarily includes unrealized foreign exchange gains and losses on the translation of the U.S. dollar debt issued from Canada (see Note 7). As at December 31, 2025, Cenovus had US$4.3 billion in U.S. dollar debt (December 31, 2024 – US$3.8 billion). In respect of these financial instruments, the impact of changes in the Canadian per U.S. dollar exchange rate would have resulted in a change to the foreign exchange (gain) loss as follows:

As at December 31,	**2025**	2024
$0.05 Increase in the Canadian per U.S. Dollar Foreign Exchange Rate	**215**	196
$0.05 Decrease in the Canadian per U.S. Dollar Foreign Exchange Rate	**(215)**	(196)

iii) Commodity Price and Foreign Exchange Rate Sensitivities

The following tables summarize the sensitivity of the fair value of Cenovus's risk management positions to independent fluctuations in commodity prices and foreign exchange rates, with all other variables held constant. Management believes the fluctuations identified in the tables below are a reasonable measure of volatility.

The impact of fluctuating commodity prices and foreign exchange rates on the Company's open risk management positions could have resulted in an unrealized gain (loss) impacting earnings before income tax as follows:

As at December 31, 2025	**Sensitivity Range**	**Increase**	**Decrease**
Crude Oil and Condensate Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	**—**	**—**
Crude Oil and Condensate Differential Price [1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	**1**	**(1)**
WCS (Hardisty) Differential Price	± US$2.50/bbl Applied to WCS Differential Hedges Tied to Production	**13**	**(13)**
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	**(4)**	**4**
Natural Gas Commodity Price	± US$0.50/Mcf Applied to Natural Gas Hedges Tied to Production	**—**	**—**
Natural Gas Basis Price	± US$0.50/Mcf Applied to Natural Gas Basis Hedges	**—**	**—**
Power Commodity Price	± C$10.00/MWh [2] Applied to Power Hedges	**39**	**(39)**

As at December 31, 2024	**Sensitivity Range**	**Increase**	**Decrease**
Crude Oil and Condensate Commodity Price	± US$10.00/bbl Applied to WTI, Condensate and Related Hedges	—	—
Crude Oil and Condensate Differential Price [1]	± US$2.50/bbl Applied to Differential Hedges Tied to Production	20	(20)
WCS (Hardisty) Differential Price	± US$2.50/bbl Applied to WCS Differential Hedges Tie to Production	(6)	6
Refined Products Commodity Price	± US$10.00/bbl Applied to Heating Oil and Gasoline Hedges	(3)	3
Natural Gas Commodity Price	± $0.50/Mcf Applied to Natural Gas Hedges Tied to Production	—	—
Natural Gas Basis Price	± US$0.25/Mcf Applied to Natural Gas Basis Hedges	1	(1)
Power Commodity Price	± C$10.00/MWh [2] Applied to Power Hedges	46	(46)
U.S. to Canadian Dollar Exchange Rate	± $0.05 in the U.S. to Canadian Dollar Exchange Rate	24	(28)

(1) Excluding WCS at Hardisty.
(2) One thousand kilowatts of electricity per hour ("MWh").

B) Credit Risk

Credit risk arises from the potential that the Company may incur a financial loss if a counterparty to a financial instrument fails to meet its financial or performance obligations in accordance with agreed terms. Cenovus has in place a Credit Policy approved by the Audit Committee and the Board of Directors, which is designed to ensure that its credit exposures are within an acceptable risk level. The Credit Policy outlines the roles and responsibilities related to credit risk, sets a framework for how credit exposures will be measured, monitored and mitigated, and sets parameters around credit concentration limits.

Cenovus assesses the credit risk of new counterparties and continues risk-based monitoring of all counterparties on an ongoing basis. A substantial portion of Cenovus's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. Cenovus's exposure to its counterparties is within its credit policy tolerances. The maximum credit risk exposure associated with accounts receivable and accrued revenues, net investment in finance leases, risk management assets and long-term receivables is the total carrying value.

As at December 31, 2025, approximately 81 percent (December 31, 2024 – 79 percent) of the Company's accounts receivable and accrued revenues were with investment grade counterparties, and 99 percent of the Company's accounts receivable were outstanding for less than 60 days. The associated average expected credit loss ("ECL") on these accounts was 0.3 percent as at December 31, 2025 (December 31, 2024 – 0.4 percent).

C) Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet all of its financial obligations as they become due. Liquidity risk also includes the risk of not being able to liquidate assets in a timely manner at a reasonable price.

As disclosed in Note 22, over the long term, Cenovus targets a Net Debt to Adjusted EBITDA ratio and Net Debt to Adjusted Funds Flow ratio of approximately 1.0 times at a WTI price of US$45.00 per barrel to manage the Company's overall debt position.

As at December 31, 2025, the Company's sources of capital included:

- $2.7 billion in cash and cash equivalents.
- $5.5 billion available on its committed credit facility.
- $1.2 billion available on its uncommitted demand facilities, of which $1.1 billion may be drawn for general purposes, or the full amount may be available to issue letters of credit.
- The base shelf prospectus, availability of which is dependent on market conditions.

Undiscounted cash outflows relating to financial liabilities are:

As at December 31, 2025	1 Year	Years 2 and 3	Years 4 and 5	Thereafter	**Total**
Accounts Payable and Accrued Liabilities	5,847	—	—	—	**5,847**
Long-Term Debt [1]	473	2,206	3,633	9,718	**16,030**
Lease Liabilities [1]	519	922	688	2,719	**4,848**

As at December 31, 2024	1 Year	Years 2 and 3	Years 4 and 5	Thereafter	Total
Accounts Payable and Accrued Liabilities	6,242	—	—	—	6,242
Short-Term Borrowings	173	—	—	—	173
Long-Term Debt [1]	526	1,910	1,989	7,286	11,711
Lease Liabilities [1]	538	824	645	2,606	4,613

(1) Principal and interest, including current portion, if applicable.

33. SUPPLEMENTARY CASH FLOW INFORMATION

A) Working Capital

As at December 31,	**2025**	2024
Total Current Assets	**9,890**	10,434
Total Current Liabilities	**6,314**	7,362
Working Capital	**3,576**	3,072

B) Changes in Non-Cash Working Capital

For the years ended December 31,	**2025 [1]**	2024
Accounts Receivable and Accrued Revenues	**(575)**	547
Income Tax Receivable	**(124)**	199
Inventories	**716**	(117)
Accounts Payable and Accrued Liabilities	**(318)**	299
Income Tax Payable	**(298)**	322
Total Change in Non-Cash Working Capital	**(599)**	1,250
Net Change in Non-Cash Working Capital – Operating Activities	**(363)**	1,305
Net Change in Non-Cash Working Capital – Investing Activities	**(236)**	(55)
Total Change in Non-Cash Working Capital	**(599)**	1,250

(1) Excludes the impacts of acquisitions (see Note 4) and the divestiture of WRB (see Note 8).

C) Cash Flows Related to Interest and Taxes

For the years ended December 31,	**2025**	2024
Interest Paid	**381**	356
Interest Received	**141**	163
Income Taxes Paid	**1,225**	868

D) Reconciliation of Liabilities

The following table provides a reconciliation of liabilities to cash flows arising from financing activities:

	Dividends Payable	**Repurchase Agreements Payable [1]**	**Short-Term Borrowings**	**Long-Term Debt**	**Lease Liabilities**
As at December 31, 2023	9	—	179	7,108	2,658
Changes From Financing Cash Flows:					
Net Issuance (Repayment) of Short-Term Borrowings	—	—	5	—	—
Principal Repayment of Leases	—	—	—	—	(299)
Dividends Paid	(1,551)	—	—	—	—
Non-Cash Changes:					
Finance and Transaction Costs	—	—	—	(16)	—
Lease Additions	—	—	—	—	363
Base Dividends Declared on Common Shares	1,255	—	—	—	—
Variable Dividends Declared on Common Shares	251	—	—	—	—
Dividends Declared on Preferred Shares	36	—	—	—	—
Exchange Rate Movements and Other	—	—	(11)	442	205
As at December 31, 2024	**—**	**—**	**173**	**7,534**	**2,927**
Acquisition	**—**	**—**	**—**	**855**	**—**
Changes From Financing Cash Flows:					
Net Issuance (Repayment) of Short-Term Borrowings	**—**	**—**	**152**	**—**	**—**
Issuance of Long-Term Debt	**—**	**—**	**—**	**5,265**	**—**
Repayment of Long-Term Debt	**—**	**—**	**—**	**(2,324)**	**—**
Principal Repayment of Leases	**—**	**—**	**—**	**—**	**(350)**
Proceeds on Repurchase Agreements	**—**	**840**	**—**	**—**	**—**
Repayment of Repurchase Agreements	**—**	**(427)**	**—**	**—**	**—**
Dividends Paid	**(1,437)**	**—**	**—**	**—**	**—**
Non-Cash Changes:					
Divestiture of Short-Term Borrowings	**—**	**—**	**(313)**	**—**	**—**
Finance and Transaction Costs	**—**	**—**	**—**	**(7)**	**—**
Lease Acquisitions	**—**		**—**	**—**	**366**
Lease Additions	**—**	**—**	**—**	**—**	**174**
Lease Divestitures	**—**	**—**	**—**	**—**	**(39)**
Lease Modifications	**—**	**—**	**—**	**—**	**150**
Base Dividends Declared on Common Shares	**1,423**	**—**	**—**	**—**	**—**
Dividends Declared on Preferred Shares	**14**	**—**	**—**	**—**	**—**
Exchange Rate Movements and Other	**—**	**(12)**	**(12)**	**(291)**	**(53)**
As at December 31, 2025	**—**	**401**	**—**	**11,032**	**3,175**

(1) Repurchase Agreements primarily relate to RINs.

34. COMMITMENTS AND CONTINGENCIES

A) Commitments

Cenovus has entered into various commitments in the normal course of operations. Commitments that have original maturities less than one year are excluded from the table below. Future payments for the Company's commitments are below:

As at December 31, 2025	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage [(1) (2)]	2,603	2,623	2,775	2,802	2,531	23,591	**36,925**
Real Estate	64	65	65	69	70	474	**807**
Obligation to Fund HCML	99	94	54	42	41	59	**389**
Other Long-Term Commitments	547	184	151	117	111	484	**1,594**
Total Commitments	3,313	2,966	3,045	3,030	2,753	24,608	**39,715**

As at December 31, 2024	1 Year	2 Years	3 Years	4 Years	5 Years	Thereafter	**Total**
Transportation and Storage [(1) (2)]	2,122	1,947	1,921	1,904	1,815	14,551	24,260
Product Purchases	14	—	—	—	—	—	14
Real Estate	63	63	61	59	63	532	841
Obligation to Fund HCML	104	105	98	56	44	105	512
Other Long-Term Commitments	411	191	187	158	117	589	1,653
Total Commitments	2,714	2,306	2,267	2,177	2,039	15,777	27,280

(1) Includes transportation commitments that are subject to regulatory approval or were approved but are not yet in service of $7.7 billion (December 31, 2024 – $854 million), of which $1.6 billion were assumed from the MEG Acquisition. Terms are up to 15 years on commencement.
(2) As at December 31, 2025, includes $1.7 billion related to transportation and storage commitments with HMLP (December 31, 2024 – $1.8 billion).

Through the MEG Acquisition, the Company assumed $8.3 billion of various transportation and storage commitments.

There were outstanding letters of credit aggregating to $341 million (December 31, 2024 – $355 million) issued as security for financial and performance conditions under certain contracts.

B) Contingencies

Legal Proceedings

Cenovus is involved in a limited number of legal claims associated with the normal course of operations. Cenovus believes that any liabilities that might arise from such matters, to the extent not provided for, are not likely to have a material effect on its Consolidated Financial Statements.

Income Tax Matters

The tax regulations and legislation and interpretations thereof in the various jurisdictions in which Cenovus operates are continually changing. As a result, there are usually a number of tax matters under review. Management believes that the provision for taxes is adequate.

35. MATERIAL ACCOUNTING POLICIES

A) Revenue Recognition

Revenue is based on the consideration specified in a contract and is recorded when control of the product or service passes to the customer in accordance with terms of the contract. Performance obligations are largely satisfied at a point in time upon the delivery of crude oil, NGLs, natural gas, and petroleum and refined products. Cenovus sells its production of crude oil, NGLs, natural gas, and petroleum and refined products generally pursuant to variable price contracts. The transaction price for variable price contracts is based on the commodity price, adjusted for quality, location and other factors. Performance obligations for crude oil and natural gas processing revenue, transportation services and transloading services are satisfied over time as the service is provided. Revenue associated with crude oil and natural gas processing, transportation services and transloading services are generally based on fixed price contracts.

Revenues are typically collected in the month following delivery. Therefore, Cenovus has elected not to adjust consideration for the effects of a financing component. The Company does not disclose information about remaining performance obligations with an original expected duration of one year or less and it does not have any long-term contracts, with the exception of certain construction contracts with HMLP and take-or-pay contracts, with unfulfilled performance obligations.

Purchases and sales of products that are entered into in contemplation of each other with the same counterparty are recorded as non-monetary exchanges on a net basis.

Cenovus has take-or-pay contracts where customers are required to take, or pay for, minimum quantities. If a customer has a right to defer delivery to a later date, Cenovus's performance obligation has not been satisfied. Revenue is deferred and recognized only when the product is delivered, or the deferral provision can no longer be extended.

The Company may enter into certain transactions whereby an asset is sold with the commitment to repurchase the same, or similar, asset from the same counterparty at a later date. These transactions are accounted for as repurchase agreements and are recognized as financing arrangements when the cost to repurchase is higher than the original price received. The asset remains on the balance sheet with any payments received recorded to accounts payable until repurchased. Any excess on repurchase is recorded to finance expense.

B) Purchased Product, Transportation and Blending

Purchased Product

Purchased product includes the costs of refining feedstock, crude oil and diluent purchased for optimization activities, and costs associated with transporting refined products to market.

Transportation and Blending

Costs paid for the transportation of crude oil, NGLs and natural gas, and the cost of diluent used in blending are recognized when the product is sold.

C) Employee Benefit Plans

The Company provides employees with a pension plan that includes either a defined contribution or defined benefit component. OPEB plans are also provided to qualifying employees. In some cases, the benefits are provided through medical care plans to which the Company, employees and retirees may contribute. In some plans, benefits are not funded before employees retire.

The cost of the defined contribution pension plan is recorded as the benefits are earned. The cost of the defined benefit pension and OPEB plans are actuarially determined using the projected unit credit method. The estimated cost is based on length of service and reflects Management's best estimate of salary escalation, longevity rates, employees' retirement age and expected future health care costs. The liability for the defined benefit pension and OPEB plans is the present value of the defined benefit obligation less the fair value of plan assets.

Pension benefit costs are recorded in operating, and general and administrative expenses, as well as PP&E and E&E assets, corresponding to where the salaries of the employees providing the service are recorded. Interest costs (income) on the net obligation (asset) are included as part of pension benefit costs. Remeasurement changes, including actuarial gains or losses related to the plan assets and defined benefit obligation, the effect of changes to the asset ceiling and return on plan assets, are recognized in OCI when they occur.

D) Deferred Income Taxes

Cenovus follows the liability method of accounting for deferred income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary difference between the accounting basis and income tax basis of an asset or liability, using the substantively enacted income tax rates expected to apply when the assets will be realized, or liabilities will be settled. The effect of a change in the enacted tax rate or laws is recognized in net earnings (loss) in the period that the change occurs, except when it relates to items recorded in equity or OCI, in which case the deferred income tax is also recorded in equity or OCI, respectively.

Deferred income tax is recognized on temporary differences arising from investments in subsidiaries, except in the case where the timing of the reversal of the temporary difference is controlled by the Company, and it is probable that the temporary difference will not reverse in the foreseeable future or when distributions can be made without incurring income taxes.

Deferred income tax assets are recognized only to the extent that it is probable that future taxable profit will be available against which the temporary differences can be utilized. Deferred income tax assets and liabilities are only offset where they arise within the same entity and tax jurisdiction.

E) Inventories

Product inventories are valued at the lower of cost, using a first-in, first-out, or weighted average cost basis, and net realizable value. Parts and supplies are valued at the lower of weighted average cost and net realizable value. The cost of inventory includes purchase costs, direct production costs, and DD&A. Net realizable value is the estimated selling price in the ordinary course of business less expected selling costs. If the carrying amount exceeds net realizable value, a write-down is recognized in net earnings (loss).

F) Exploration and Evaluation Assets

E&E assets consist of exploratory projects for crude oil, NGLs and natural gas that are generally pending the determination of proved reserves. The costs to acquire non-producing oil and gas properties, licences to explore, drilling exploratory wells and the costs to evaluate the commercial potential of the resources are initially capitalized as E&E assets. Costs incurred prior to obtaining the legal right to explore an area (pre-exploration costs) are recorded as exploration expense when incurred.

Once technical feasibility and commercial viability of an E&E asset is established, the carrying value is transferred to PP&E. If Management does not consider an E&E asset to be technically feasible and commercially viable, the related capital costs are written off as exploration expense.

G) Property, Plant and Equipment

PP&E is recorded at cost less accumulated DD&A, adjusted for impairment losses and impairment reversals. Capitalized costs include the purchase price, construction or development expenditures, directly attributable internal costs, decommissioning liabilities and, for qualifying assets, borrowing costs. Costs incurred to install the asset and make it ready for its intended use are also capitalized. Expenditures that improve the productive capacity or extend the life of an asset are capitalized, while maintenance costs and repairs are expensed as incurred.

Crude Oil and Natural Gas Properties

Development and production assets are capitalized by area. Costs includes all expenditures associated with the development of crude oil and natural gas properties and related infrastructure, as well as expenditures transferred from E&E assets.

Development and production assets are depleted using the unit-of-production method based on estimated reserves determined using forward prices and costs. The unit-of-production depletion rate takes into account expenditures incurred to date, together with the future development expenditures required to develop reserves. Onshore assets are depleted based on estimated proved reserves. Offshore assets are depleted based on estimated proved developed producing reserves or proved plus probable reserves.

Refining Assets

The Company's refineries and plants are composed of highly integrated and interdependent crude oil and other feedstock processing facilities and supporting infrastructure. Where facilities and equipment, including major components, are significant in relation to the total cost of the assets and have different useful lives, they are depreciated on a straight-line basis over the estimated service life of each component. Major components are depreciated as follows:

- Land improvements and buildings: 10 to 40 years.
- Office equipment and vehicles: 3 to 15 years.
- Rail facilities: 10 to 40 years.
- Refining equipment: 5 to 60 years.

Processing, Transportation and Storage Assets, Commercial Fuels Business and Other

Depreciation for substantially all other PP&E is calculated on a straight-line basis based on the estimated useful lives of assets, which range from three to 60 years. Land is not depreciated.

H) Impairments of Assets

Impairment and Impairment Reversals of Non-Financial Assets

PP&E, E&E assets and ROU assets are reviewed separately for indicators of impairment on a quarterly basis or when facts and circumstances suggest that the carrying amount of an asset or CGU may exceed its recoverable amount. Goodwill is tested for impairment at least annually. E&E assets are also tested for impairment immediately prior to being transferred to PP&E.

Cenovus allocates E&E assets to a related CGU containing development and production assets when testing for impairment. ROU assets may be tested as part of a CGU, as a separate CGU, or as an individual asset. Goodwill is allocated to CGUs that benefited from the historical business combinations.

The recoverable amount of the asset or CGU is estimated as the greater of value-in-use ("VIU") and FVLCOD. VIU is estimated as the present value of the future cash flows expected to arise from the continuing use of an asset or CGU. FVLCOD is the amount that would be realized from the disposition of an asset or CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCOD for upstream assets is estimated based on the discounted after-tax cash flows of reserves using forward prices, future operating costs and future capital expenditures consistent with Cenovus's IQREs, and may consider an evaluation of comparable asset transactions. FVLCOD for downstream assets is estimated based on discounted after-tax cash flows of refined product production, forward crude oil prices, forward crack spreads, net of RINs, future capital expenditures, future operating costs and discount rates. Forward prices are based on third-party consultant forecasts.

If the recoverable amount of the asset or CGU is less than the carrying amount, an impairment loss is recognized. The impairment loss first reduces the goodwill allocated to a CGU, if any, and then reduces the carrying amount of the remaining assets in the CGU. Impairment losses on PP&E and ROU assets are recognized as additional DD&A. E&E asset impairments or write-downs are recognized as exploration expense.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for indicators that the impairment losses may no longer exist or may have decreased. If such indications exist, the carrying amount of the asset or CGU is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined had no impairment loss been recognized in prior periods. The reversal is recognized as a reduction to DD&A.

Impairment of Financial Assets

At each reporting date, the Company assesses the ECLs associated with its financial assets measured at amortized cost. For accounts receivable, Cenovus measures loss allowances at an amount equal to lifetime ECLs. ECLs are estimated as the difference between the cash flows due to the Company and the cash flows the Company expects to receive, discounted at the effective interest rate on initial recognition. Changes in ECLs are recognized in other income (loss).

I) Leases

As Lessee

The Company recognizes an ROU asset and a lease liability when the leased asset is available for use.

Lease liabilities are measured at the present value of lease payments and estimated costs to dismantle and remove the underlying leased asset. Lease liabilities are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Lease payments include fixed payments, as well as variable payments based on an index or rate. Lease liabilities are re-measured when there is a change in the future lease payments due to a change in an index or rate. Re-measurement will also occur if there is a change in the expected residual value guarantee or if the Company reconsiders the exercise of a purchase, extension or termination option that is within its control. When the lease liability is re-measured, an adjustment is also made to the carrying amount of the ROU asset.

The ROU asset is initially measured at cost, which includes the initial measurement of the lease liability and initial direct costs. The cost is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset or the lease term.

Leases with a term of less than twelve months, or leases of an asset with a low value, are recognized over the lease term as an operating, transportation, or general and administrative expense. The Company has elected not to separate non-lease components for storage tanks.

As Lessor

Leases where the Company transfers substantially all of the risks and rewards from ownership of an underlying asset are classified as financing leases. The Company recognizes a receivable at an amount equal to the net investment in the lease, which is the present value of the aggregate of lease payments receivable by the lessor. Cenovus recognizes lease payments for operating leases on a straight-line basis over the term of the lease as other income.

J) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting in which the identifiable assets acquired, liabilities assumed and non-controlling interest, if any, are recognized and measured to their fair value at the date of acquisition, with certain exceptions such as ROU assets, lease liabilities, income taxes and stock-based compensation.

When a business combination is achieved in stages, the Company re-measures its pre-existing interest at the acquisition date fair value and recognizes the resulting gain or loss, if any, in net earnings (loss).

K) Provisions

A provision is recognized if the Company has a present legal or constructive obligation as a result of a past event. It must be possible to reliably estimate the obligation and it is more likely than not that an outflow of economic benefits will be required to settle the obligation. Where applicable, the expected future cash flows of a provision are discounted using a credit-adjusted risk-free rate. The increase in the provision due to the passage of time is recognized as a finance expense.

Decommissioning Liabilities

The Company will be required to retire its tangible long-lived assets such as producing well sites, upstream processing facilities, surface and subsea plant and equipment, refining facilities and the crude-by-rail terminal. When a disturbance occurs, the Company recognizes a decommissioning liability equal to the present value of estimated future expenditures required to settle the obligation using a credit-adjusted risk-free rate. The initial estimate of the liability is added to the cost of the related asset and amortized over the useful life of the asset. Changes in the provision arising from revisions to expected timing or future decommissioning costs are recognized as a change in the decommissioning liability and the related long-lived asset. Actual expenditures incurred are charged against the liability.

Renewable Fuel Obligations

The Company's U.S. refining operations incur an RVO, which the Company settles annually using RINs. After considering RINs on hand, the RVO is measured at the expected market price, or on a contracted forward rate, if applicable, of the additional RINs required to settle the compliance obligation. RINs purchased with biofuel are measured using the average market price in the month purchased. RINs purchased on a secondary market are measured at cost. RINs are not amortized. A net RIN position is presented in other assets and a net RVO position is included in other liabilities.

L) Share Capital and Warrants

Common shares, treasury shares and preferred shares are classified as equity. When the Company purchases its own common shares or preferred shares, share capital is reduced by the weighted average carrying value of the shares purchased. Any difference between the purchase price and the carrying value is recorded to paid in surplus to the extent available, and subsequently to retained earnings. No gain or loss is recognized on the purchase, sale, issuance or cancellation of equity instruments. Common shares and preferred shares are cancelled upon purchase.

Common shares purchased under the employee benefit plan are measured at their cost to acquire and are recorded as treasury shares. When the treasury shares are distributed under the employee benefit plan, the treasury shares are reduced by their weighted average carrying value with the excess or deficiency from the settled employee long-term incentive liability recognized in paid in surplus to the extent available and subsequently to retained earnings.

Transaction costs directly attributable to the issue or repurchase of common shares, treasury shares and preferred shares are recognized as a deduction from equity, net of any income taxes.

Warrants are classified as equity and are measured at fair value upon issuance. On exercise, the cash consideration received by the Company and the associated carrying value of the warrants are recorded as share capital.

M) Stock-Based Compensation

Cenovus has a number of stock-based compensation plans that include stock options with associated NSRs, PSUs, RSUs and DSUs. Stock-based compensation costs are recorded in general and administrative expenses.

Stock Options With Associated Net Settlement Rights

NSRs are accounted for as equity instruments, which are measured at fair value on the grant date using the Black-Scholes-Merton valuation model, and are not revalued at each reporting date. The fair value is recognized as stock-based compensation over the vesting period, with a corresponding increase recorded as paid in surplus. On exercise, the cash consideration received by the Company and the associated paid in surplus are recorded as share capital.

Performance, Restricted and Deferred Share Units

PSUs, RSUs and DSUs are accounted for as liability instruments and are measured at fair value based on the market value of Cenovus's common shares at each period end. The fair value is recognized as stock-based compensation over the vesting period. Fair value fluctuations are recognized in stock-based compensation in the period they occur. Cenovus has certain PSU and RSU plans that may be settled in cash or common shares at the Company's option and certain plans that are settled in cash.

N) Financial Instruments

Financial assets are classified and measured based on the objective of the business model for managing the instrument or group of instruments, and the contractual terms of the cash flows as noted below. Financial liabilities are measured at amortized cost or fair value through profit or loss as noted below.

Classification	Instrument Type
Amortized Cost	Cash and cash equivalents, restricted cash, accounts receivable and accrued revenues, accounts payable and accrued liabilities, short-term borrowings, lease liabilities and long-term debt.
Fair Value Through Profit or Loss	Risk management assets and liabilities, contingent payments and equity investments in public companies.
Fair Value Through Other Comprehensive Income (Loss)	Certain equity investments not held for trading for which an irrevocable election was made at initial recognition.

All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the financial instrument.

Cenovus uses observable market inputs as much as possible when estimating the fair value of financial instruments. Inputs are categorized into the following levels based on how observable the inputs are:

- Level 1: Quoted prices in active markets for identical assets and liabilities.
- Level 2: Inputs other than quoted prices included within Level 1, that are observable for the asset or liability either directly or indirectly.
- Level 3: Unobservable inputs for the asset or liability.

Financial assets and liabilities are not offset unless the Company has the current legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously.

Derivatives

Derivative financial instruments are primarily used to manage economic exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Policies and procedures are in place with respect to required documentation and approvals for the use of derivative financial instruments.

Derivative financial instruments are measured at fair value through profit or loss unless designated for hedge accounting. Derivative instruments not designated as hedges are recorded using mark-to-market accounting whereby any changes in fair value are recorded as a gain or loss on risk management. The estimated fair value of derivative instruments is based on quoted market prices or, in their absence, third-party market indications and forecasts.

O) Foreign Currency Translation

The Company's functional and presentation currency is Canadian dollars. The Company uses the direct method of consolidation. Translation gains and losses relating to foreign operations with a functional currency different from the presentation currency are recognized in OCI as cumulative translation adjustments. When the Company disposes of an interest in a foreign operation or loses control, joint control, or significant influence over a foreign operation, the foreign currency gains or losses accumulated in OCI related to the foreign operation are recognized in net earnings.

Transactions in foreign currencies are translated to the respective functional currencies at exchange rates in effect at the dates of the transactions. Monetary assets and liabilities of Cenovus that are denominated in foreign currencies are translated into its functional currency at the rates of exchange in effect at the reporting date. Any gains or losses are recognized in net earnings (loss).

P) Recent Accounting Pronouncements

New Accounting Standards and Interpretations not yet Adopted

There are new accounting standards, amendments to accounting standards and interpretations that are effective for annual periods beginning on or after January 1, 2026, and have not been applied in preparing the Consolidated Financial Statements for the year ended December 31, 2025. The standards applicable to Cenovus are as follows and will be adopted on their respective dates:

Financial Instruments

On May 30, 2024, the IASB issued amendments to IFRS 9, *"Financial Instruments",* and IFRS 7, *"Financial Instruments: Disclosures".* The amendments include clarifications on the derecognition of financial liabilities and the classification of certain financial assets. In addition, new disclosure requirements for equity instruments designated as FVOCI were added. The amendments are effective for annual periods beginning on or after January 1, 2026, and will be applied retrospectively. The amendments to IFRS 9 and IFRS 7 will not have a material impact on the Consolidated Financial Statements.

Presentation and Disclosure in Financial Statements

On April 9, 2024, the IASB issued IFRS 18, *"Presentation and Disclosure in Financial Statements"* ("IFRS 18"), which will replace International Accounting Standard 1, *"Presentation of Financial Statements"*. IFRS 18 will establish a revised structure for the Consolidated Statements of Comprehensive Income (Loss) and improve comparability across entities and reporting periods.

IFRS 18 is effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The Company is continuing to evaluate the impacts of adopting IFRS 18 on the Consolidated Financial Statements. Cenovus will adopt IFRS 18 effective January 1, 2027, using the retrospective approach.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

($ millions, except per share amounts)

	Three Months Ended					Twelve Months Ended	
	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
Revenues							
Upstream							
Oil Sands	**6,573**	5,917	5,921	6,996	6,217	**25,407**	25,173
Conventional	**727**	417	537	924	761	**2,605**	2,983
Offshore	**317**	370	315	426	348	**1,428**	1,473
Total Upstream Revenue	**7,617**	6,704	6,773	8,346	7,326	**29,440**	29,629
Downstream							
Canadian Refining	**1,156**	1,353	1,288	1,282	1,263	**5,079**	5,310
U.S. Refining	**4,158**	7,082	6,455	6,423	6,574	**24,118**	28,308
Total Downstream Revenue	**5,314**	8,435	7,743	7,705	7,837	**29,197**	33,618
Corporate and Eliminations	**(2,048)**	(1,944)	(2,197)	(2,752)	(2,350)	**(8,941)**	(8,970)
Total Revenues	**10,883**	13,195	12,319	13,299	12,813	**49,696**	54,277
Operating Margin							
Upstream							
Oil Sands	**2,225**	2,293	1,822	2,544	2,340	**8,884**	9,791
Conventional	**159**	41	84	173	88	**457**	291
Offshore	**244**	256	231	331	242	**1,062**	1,039
Total Upstream Operating Margin (1)	**2,628**	2,590	2,137	3,048	2,670	**10,403**	11,121
Downstream							
Canadian Refining	**68**	111	107	68	47	**354**	(80)
U.S. Refining	**81**	253	(178)	(305)	(443)	**(149)**	(232)
Total Downstream Operating Margin (1)	**149**	364	(71)	(237)	(396)	**205**	(312)
Total Operating Margin (2)	**2,777**	2,954	2,066	2,811	2,274	**10,608**	10,809
Cash From (Used in) Operating Activities and Adjusted Funds Flow							
Cash From (Used in) Operating Activities	**2,408**	2,131	2,374	1,315	2,029	**8,228**	9,235
Deduct (Add Back):							
Settlement of Decommissioning Liabilities	**(82)**	(94)	(68)	(36)	(64)	**(280)**	(234)
Net Change in Non-Cash Working Capital	**(184)**	(241)	923	(861)	492	**(363)**	1,305
Adjusted Funds Flow (2)	**2,674**	2,466	1,519	2,212	1,601	**8,871**	8,164
Per Share - Basic (2)	**1.47**	1.38	0.84	1.21	0.88	**4.90**	4.41
Per Share - Diluted (2)	**1.46**	1.38	0.84	1.21	0.87	**4.87**	4.38
Net Earnings (Loss)							
Net Earnings (Loss)	**934**	1,286	851	859	146	**3,930**	3,142
Per Share - Basic	**0.51**	0.72	0.47	0.47	0.08	**2.16**	1.68
Per Share - Diluted	**0.50**	0.72	0.45	0.47	0.07	**2.15**	1.67
Capital Investment							
Upstream							
Oil Sands	**862**	675	644	763	773	**2,944**	2,714
Conventional	**151**	107	73	122	121	**453**	421
Offshore							
Atlantic	**174**	194	253	227	312	**848**	1,077
Asia Pacific	**32**	23	17	14	24	**86**	68
Total Offshore	**206**	217	270	241	336	**934**	1,145
Total Upstream Capital Investment	**1,219**	999	987	1,126	1,230	**4,331**	4,280
Downstream							
Canadian Refining	**34**	33	28	22	63	**117**	208
U.S. Refining	**99**	120	146	77	168	**442**	488
Total Downstream Capital Investment	**133**	153	174	99	231	**559**	696
Corporate	**8**	2	3	4	17	**17**	39
Total Capital Investment	**1,360**	1,154	1,164	1,229	1,478	**4,907**	5,015

(1) Specified financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) Non-GAAP financial measure or contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.

SUPPLEMENTAL INFORMATION *(unaudited)*

Financial Statistics

	Three Months Ended					Twelve Months Ended	
Financial Metrics	**Dec. 31, 2025**	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
Free Funds Flow [1]	**1,314**	1,312	355	983	123	**3,964**	3,149
Excess Free Funds Flow [1]	**(1,597)**	745	(306)	373	(416)	**(785)**	1,297
Long-Term Debt, Including Current Portion	**11,032**	7,156	7,241	7,524	7,534	**11,032**	7,534
Total Debt	**11,032**	7,156	7,497	7,847	7,707	**11,032**	7,707
Net Debt	**8,292**	5,255	4,934	5,079	4,614	**8,292**	4,614
Net Debt to Adjusted Funds Flow [2] (times)	**0.9**	0.7	0.7	0.6	0.6	**0.9**	0.6
Net Debt to Adjusted EBITDA [2] (times)	**0.9**	0.6	0.6	0.5	0.5	**0.9**	0.5
Income Tax and Exchange Rates							
Effective Tax Rate on Net Earnings (Loss) (percent)						**12.2**	22.8
Foreign Exchange Rates							
US$ per C$1 - Average	**0.717**	0.726	0.723	0.697	0.715	**0.716**	0.730
US$ per C$1 - Period End	**0.730**	0.718	0.733	0.696	0.695	**0.730**	0.695
RMB per C$1 - Average	**5.084**	5.197	5.226	5.069	5.142	**5.144**	5.255
Common Share Information							
Common Shares Outstanding (millions)							
Period End	**1,883**	1,766	1,806	1,823	1,825	**1,883**	1,825
Weighted Average - Basic	**1,819**	1,789	1,811	1,821	1,826	**1,810**	1,850
Weighted Average - Diluted	**1,836**	1,793	1,819	1,831	1,839	**1,820**	1,863
Base Dividend ($ per share)	**0.200**	0.200	0.200	0.180	0.180	**0.780**	0.680
Variable Dividend ($ per share)	**—**	—	—	—	—	**—**	0.135
Closing Price							
Toronto Stock Exchange (C$ per share)	**23.22**	23.63	18.53	20.00	21.79	**23.22**	21.79
New York Stock Exchange (US$ per share)	**16.92**	16.99	13.60	13.91	15.15	**16.92**	15.15
Total Share Volume Traded (millions)	**1,933**	2,132	1,600	1,357	1,061	**7,022**	4,713
Selected Average Benchmark Prices							
(Average US$/bbl, unless otherwise indicated)							
Crude Oil Prices							
Dated Brent	**63.69**	69.07	67.82	75.66	74.69	**69.06**	80.76
West Texas Intermediate ("WTI")	**59.14**	64.93	63.74	71.42	70.27	**64.81**	75.72
Differential Dated Brent - WTI	**4.55**	4.14	4.08	4.24	4.42	**4.25**	5.04
Western Canadian Select ("WCS") at Hardisty	**47.94**	54.54	53.47	58.75	57.71	**53.68**	60.97
Differential WTI - WCS at Hardisty	**11.20**	10.39	10.27	12.67	12.56	**11.13**	14.75
WCS at Nederland	**55.63**	62.58	61.00	67.74	65.69	**61.74**	69.69
Differential WTI - WCS at Nederland	**3.51**	2.35	2.74	3.68	4.58	**3.07**	6.03
Condensate (C5 at Edmonton)	**57.01**	63.10	63.46	69.88	70.66	**63.36**	72.94
Differential Condensate - WTI Premium/(Discount)	**(2.13)**	(1.83)	(0.28)	(1.54)	0.39	**(1.45)**	(2.78)
Differential Condensate - WCS at Hardisty Premium/(Discount)	**9.07**	8.56	9.99	11.13	12.95	**9.68**	11.97
Synthetic at Edmonton	**57.84**	66.26	64.72	69.07	71.11	**64.47**	75.07
Differential Synthetic - WTI Premium/(Discount)	**(1.30)**	1.33	0.98	(2.35)	0.84	**(0.34)**	(0.65)
Refined Product Prices							
Chicago Regular Unleaded Gasoline	**70.66**	84.87	84.61	83.08	78.95	**80.81**	89.95
Chicago Ultra-low Sulphur Diesel	**90.70**	97.78	86.91	89.12	89.28	**91.13**	97.47
Refining Benchmarks							
Chicago 3-2-1 Crack Spread [3]	**18.20**	24.24	21.64	13.68	12.12	**19.44**	16.74
Group 3 3-2-1 Crack Spread [3]	**19.25**	23.72	23.07	16.48	12.66	**20.63**	16.81
Renewable Identification Numbers ("RINs")	**6.04**	6.33	6.12	4.76	4.02	**5.81**	3.74
Upgrading Differential [4] (C$/bbl)	**13.53**	15.99	15.46	14.69	18.64	**14.92**	19.21
Natural Gas Prices							
AECO [5] (C$/Mcf)	**2.23**	0.63	1.69	2.17	1.48	**1.68**	1.46
NYMEX [6] (US$/Mcf)	**3.55**	3.07	3.44	3.65	2.79	**3.43**	2.27

(1) Non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) Calculated on a trailing twelve-month basis.
(3) The average 3-2-1 crack spread is a general market indicator of the Adjusted Refining Margin and is valued on a last-in, first-out accounting basis. The benchmark market crack spreads do not precisely mirror the configuration and product output of our refineries, or the location we sell product.
(4) The upgrading differential is the difference between synthetic crude oil at Edmonton and Lloydminster Blend crude oil at Hardisty. The upgrading differential does not precisely mirror the configuration and the product output of our Canadian Refining assets; however, it is used as a general market indicator.
(5) Alberta Energy Company ("AECO") 5A natural gas daily index.
(6) New York Mercantile Exchange ("NYMEX") natural gas monthly index.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Upstream

Upstream Production Volumes [1]	Three Months Ended					Twelve Months Ended	
	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
Crude Oil and Natural Gas Liquids (Mbbls/d)							
Oil Sands Bitumen							
Foster Creek	**220.1**	215.4	186.1	202.7	195.2	**206.1**	196.0
Christina Lake [2]	**308.9**	251.7	217.9	237.8	251.4	**254.3**	234.2
Sunrise	**60.3**	52.4	50.3	52.1	53.1	**53.8**	49.6
Lloydminster Thermal	**106.9**	95.7	97.8	109.9	108.9	**102.6**	111.5
Lloydminster Conventional Heavy Oil	**28.1**	25.4	25.0	21.8	18.0	**25.1**	17.6
Total Oil Sands Production	**724.3**	640.6	577.1	624.3	626.6	**641.9**	608.9
Conventional [3]							
Light Crude Oil	**5.4**	5.0	4.5	5.2	4.8	**5.0**	4.9
Natural Gas Liquids [4]	**20.8**	23.0	20.4	20.5	19.7	**21.2**	21.0
Total Conventional Production	**26.2**	28.0	24.9	25.7	24.5	**26.2**	25.9
Offshore Natural Gas Liquids							
Asia Pacific - China	**5.8**	3.1	7.9	8.8	9.1	**6.3**	9.3
Asia Pacific - Indonesia [5]	**1.3**	1.7	1.6	0.5	2.9	**1.3**	1.7
Offshore Light Crude Oil							
Atlantic	**16.9**	11.3	12.5	11.6	7.5	**13.1**	8.0
Total Offshore Production	**24.0**	16.1	22.0	20.9	19.5	**20.7**	19.0
Total Liquids Production	**774.5**	684.7	624.0	670.9	670.6	**688.8**	653.8
Conventional Natural Gas (MMcf/d)							
Oil Sands	**13.6**	13.7	16.5	11.4	11.8	**13.8**	11.1
Conventional [3]	**565.4**	593.2	569.2	589.3	560.5	**579.3**	563.8
Offshore							
Asia Pacific - China	**195.8**	192.5	179.7	199.0	200.8	**191.8**	199.5
Asia Pacific - Indonesia [5]	**85.6**	90.1	86.0	88.2	100.2	**87.5**	85.8
Total Conventional Natural Gas Production	**860.4**	889.5	851.4	887.9	873.3	**872.4**	860.2
Total Upstream Production (MBOE/d) [6]	**917.9**	832.9	765.9	818.9	816.0	**834.2**	797.2

Effective Royalty Rates [7] (percent)							
Oil Sands							
Foster Creek	**19.1**	25.4	20.5	24.4	24.2	**22.5**	24.0
Christina Lake [2]	**22.1**	27.9	23.9	26.8	30.2	**25.3**	27.3
Sunrise	**6.7**	5.3	6.3	6.6	5.8	**6.2**	6.1
Lloydminster [8]	**12.6**	11.9	13.2	11.4	14.3	**12.2**	11.7
Conventional [3]	**6.5**	9.3	7.4	9.0	8.4	**8.0**	10.3
Offshore							
Asia Pacific - China	**7.1**	5.3	7.7	7.6	7.8	**7.0**	7.7
Asia Pacific - Indonesia [5]	**16.7**	24.8	24.8	30.1	24.1	**24.2**	16.1
Atlantic	**0.9**	1.0	0.9	1.0	1.0	**1.0**	0.7

(1) Before royalties.
(2) Includes results of the acquisition of MEG Energy Corp. from November 13, 2025.
(3) 2025 reported production volumes and effective royalty rates reflect Cenovus's 30 percent equity interest in Duvernay Energy Corporation ("Duvernay"), which is accounted for using the equity method in the interim Consolidated Financial Statements.
(4) Natural gas liquids include condensate volumes.
(5) Reported production volumes and effective royalty rates reflect Cenovus's 40 percent equity interest in Husky-CNOOC Madura Ltd. ("HCML"), which is accounted for using the equity method in the interim Consolidated Financial Statements.
(6) Natural gas volumes have been converted to barrels of oil equivalent ("BOE") on the basis of six thousand cubic feet ("Mcf") to one barrel ("bbl"). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared to natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.
(7) Effective royalty rates are equal to royalty expense divided by product revenue, net of transportation expenses, excluding realized (gain) loss on risk management.
(8) Composed of the Lloydminster thermal and Lloydminster conventional heavy oil assets.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Upstream

	Three Months Ended					Twelve Months Ended	
Oil Sands - Netbacks [1]	**Dec. 31, 2025**	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
Foster Creek							
Bitumen ($/bbl)							
Realized Sales Price	**68.76**	79.46	77.96	87.26	85.87	**78.21**	84.49
Royalties	**11.04**	16.86	12.23	17.40	16.73	**14.40**	17.03
Transportation and Blending	**10.90**	13.13	18.41	15.85	16.61	**14.36**	13.57
Operating	**8.77**	8.57	12.34	9.82	9.60	**9.76**	9.87
Netback	**38.05**	40.90	34.98	44.19	42.93	**39.69**	44.02
Christina Lake [2]							
Bitumen ($/bbl)							
Realized Sales Price	**60.39**	69.92	65.51	75.07	72.86	**67.23**	75.74
Royalties	**11.63**	17.49	14.19	18.48	20.14	**15.21**	18.86
Transportation and Blending	**7.71**	7.14	6.07	6.12	6.08	**6.86**	6.53
Operating	**8.73**	6.61	8.70	8.76	8.25	**8.21**	8.63
Netback	**32.32**	38.68	36.55	41.71	38.39	**36.95**	41.72
Sunrise							
Bitumen ($/bbl)							
Realized Sales Price	**67.88**	79.50	70.07	87.30	79.30	**75.79**	86.07
Royalties	**3.62**	3.41	3.47	4.56	3.86	**3.75**	4.26
Transportation and Blending	**13.81**	14.97	15.28	18.07	12.32	**15.42**	16.07
Operating	**15.36**	17.45	20.26	17.55	14.84	**17.53**	14.36
Netback	**35.09**	43.67	31.06	47.12	48.28	**39.09**	51.38
Lloydminster [3]							
Bitumen and Heavy Crude Oil ($/bbl)							
Realized Sales Price	**61.69**	71.04	69.69	78.93	75.16	**70.17**	79.65
Royalties	**7.37**	8.06	8.74	8.61	10.15	**8.18**	8.84
Transportation and Blending	**2.99**	3.24	3.28	3.42	3.71	**3.23**	3.95
Operating	**18.16**	22.57	21.12	18.46	17.32	**20.01**	17.52
Netback	**33.17**	37.17	36.55	48.44	43.98	**38.75**	49.34
Total Oil Sands ($/bbl)							
Realized Sales Price	**63.82**	74.07	70.78	80.99	77.83	**72.07**	80.20
Royalties	**10.02**	14.28	11.43	15.03	15.64	**12.61**	14.92
Transportation and Blending	**8.33**	9.02	10.18	9.85	9.31	**9.28**	9.00
Operating	**11.00**	11.21	13.60	11.77	11.10	**11.81**	11.40
Netback	**34.47**	39.56	35.57	44.34	41.78	**38.37**	44.88
Conventional - Netbacks [1]							
Total Conventional ($/BOE) [4]							
Realized Sales Price	**29.15**	20.69	24.19	34.01	25.18	**26.95**	25.18
Royalties	**1.14**	1.04	1.18	1.83	1.34	**1.30**	1.73
Transportation and Blending	**5.51**	5.47	5.27	5.49	4.83	**5.44**	4.98
Operating	**8.13**	10.33	9.95	10.92	10.91	**9.84**	11.99
Netback	**14.37**	3.85	7.79	15.77	8.10	**10.37**	6.48

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) Includes results of the acquisition of MEG Energy Corp. from November 13, 2025.
(3) Composed of the Lloydminster thermal and Lloydminster conventional heavy oil assets.
(4) See footnote 6 on page 3 of this Supplemental for BOE definition. 2025 reported per-unit values reflect Cenovus's 30 percent equity interest in the Duvernay joint venture.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Upstream

Offshore - Netbacks [1]	Three Months Ended					Twelve Months Ended	
	Dec. 31, 2025	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
China							
Natural Gas Liquids ($/bbl)							
Realized Sales Price	**87.06**	93.57	86.96	97.29	90.91	**91.30**	95.64
Royalties	**13.83**	5.38	13.39	13.96	14.28	**12.71**	13.95
Operating	**10.33**	8.21	8.72	6.00	8.77	**8.10**	7.58
Conventional Natural Gas ($/Mcf)							
Realized Sales Price	**12.71**	12.28	12.29	12.79	12.92	**12.52**	12.66
Royalties	**0.67**	0.65	0.65	0.68	0.68	**0.66**	0.67
Operating	**1.62**	1.38	1.45	1.00	1.46	**1.36**	1.27
Asia Pacific - China Total ($/BOE) [2]							
Realized Sales Price	**77.86**	75.41	76.49	81.01	80.39	**77.81**	80.26
Royalties	**5.51**	4.03	5.88	6.13	6.28	**5.43**	6.19
Operating	**9.82**	8.26	8.72	6.00	8.77	**8.16**	7.61
Netback	**62.53**	63.12	61.89	68.88	65.34	**64.22**	66.46
Indonesia							
Natural Gas Liquids ($/bbl)							
Realized Sales Price	**95.97**	93.23	93.70	117.54	101.42	**96.59**	108.19
Royalties	**28.44**	39.01	34.14	40.97	52.25	**34.99**	52.99
Operating	**16.15**	9.27	9.28	9.07	10.69	**11.00**	9.93
Conventional Natural Gas ($/Mcf)							
Realized Sales Price	**9.18**	8.57	9.19	10.45	8.97	**9.34**	8.63
Royalties	**1.35**	1.83	2.07	3.11	1.35	**2.09**	0.68
Operating	**2.60**	1.48	1.78	1.79	1.87	**1.90**	1.84
Asia Pacific - Indonesia Total ($/BOE) [2]							
Realized Sales Price	**58.46**	55.57	59.06	64.65	60.88	**59.31**	57.82
Royalties	**9.76**	13.77	14.65	19.44	14.66	**14.34**	9.32
Operating	**15.62**	8.89	10.56	10.67	11.16	**11.39**	10.93
Netback	**33.08**	32.91	33.85	34.54	35.06	**33.58**	37.57
Total Asia Pacific [3]							
Natural Gas Liquids ($/bbl)							
Realized Sales Price	**88.68**	93.45	88.12	98.46	93.47	**92.19**	97.59
Royalties	**16.49**	17.16	16.96	15.52	23.51	**16.45**	20.02
Operating	**11.39**	8.58	8.82	6.17	9.24	**8.59**	7.95
Conventional Natural Gas ($/Mcf)							
Realized Sales Price	**11.63**	11.10	11.29	12.07	11.60	**11.52**	11.45
Royalties	**0.88**	1.03	1.11	1.42	0.91	**1.11**	0.67
Operating	**1.92**	1.41	1.56	1.24	1.60	**1.53**	1.44
Asia Pacific - Total ($/BOE) [2]							
Realized Sales Price	**72.27**	69.03	71.31	76.65	74.23	**72.39**	74.13
Royalties	**6.74**	7.16	8.48	9.68	8.93	**8.04**	7.05
Operating	**11.49**	8.46	9.26	7.24	9.53	**9.10**	8.52
Netback	**54.04**	53.41	53.57	59.73	55.77	**55.25**	58.56
Atlantic							
Light Crude Oil ($/bbl)							
Realized Sales Price	**86.58**	95.29	100.23	102.63	102.78	**97.11**	109.58
Royalties	**0.78**	0.96	0.94	1.04	1.00	**0.95**	0.72
Transportation and Blending	**3.50**	4.07	4.14	4.25	4.27	**4.04**	3.81
Operating	**53.51**	59.90	61.44	45.47	114.23	**54.07**	97.70
Netback	**28.79**	30.36	33.71	51.87	(16.72)	**38.05**	7.35

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.
(2) See footnote 6 on page 3 of this Supplemental for BOE definition.
(3) Reported per-unit values reflect Cenovus's 40 percent equity interest in the HCML joint venture.

SUPPLEMENTAL INFORMATION *(unaudited)*

Operating Statistics - Downstream

	Three Months Ended					Twelve Months Ended	
Canadian Refining	**Dec. 31, 2025**	Sep. 30, 2025	Jun. 30, 2025	Mar. 31, 2025	Dec. 31, 2024	**Dec. 31, 2025**	Dec. 31, 2024
Operable Capacity (Mbbls/d)	**108.0**	108.0	108.0	108.0	108.0	**108.0**	108.0
Total Processed Inputs (Mbbls/d)	**122.6**	114.8	120.7	119.5	112.1	**119.4**	96.6
Crude Oil Unit Throughput (Mbbls/d)	**112.9**	105.4	112.4	111.9	104.4	**110.7**	90.5
Crude Unit Utilization (percent)	**105**	98	104	104	97	**103**	84
Total Refined Product Production (Mbbls/d)							
Synthetic Crude Oil	**52.1**	48.3	55.3	52.4	48.8	**52.0**	41.0
Asphalt	**18.7**	19.5	16.7	16.6	16.8	**17.9**	15.7
Diesel	**16.1**	14.2	15.1	15.5	13.4	**15.2**	10.8
Other	**39.2**	35.0	36.9	37.7	35.6	**37.2**	30.8
Total Refined Product Production (Mbbls/d)	**126.1**	117.0	124.0	122.2	114.6	**122.3**	98.3
Ethanol (Mbbls/d)	**5.2**	5.3	5.0	4.3	3.8	**5.0**	4.8
Total Production (Mbbls/d)	**131.3**	122.3	129.0	126.5	118.4	**127.3**	103.1
Adjusted Refining Margin [1] ($/bbl)	**19.57**	21.76	19.64	17.33	16.96	**19.57**	20.72
Operating Expenses - Upgrading and Refining [2]	**152**	120	117	116	131	**505**	798
Operating Expenses - Excluding Turnaround Costs	**151**	120	116	116	127	**503**	544
Operating Expenses - Turnaround Costs	**1**	—	1	—	4	**2**	254
Per-Unit Operating Expenses [2] [3] ($/bbl)	**13.43**	11.38	10.70	10.81	12.65	**11.59**	22.56
Per-Unit Operating Expenses - Excluding Turnaround Costs	**13.35**	11.38	10.63	10.81	12.26	**11.54**	15.38
Per-Unit Operating Expenses - Turnaround Costs	**0.08**	—	0.07	—	0.39	**0.05**	7.18
U.S. Refining							
Operable Capacity [4] (Mbbls/d)	**364.8**	612.3	612.3	612.3	612.3	**549.9**	612.3
Total Processed Inputs (Mbbls/d)	**375.8**	642.8	594.2	581.0	588.4	**548.1**	581.4
Crude Oil Unit Throughput (Mbbls/d)	**352.6**	605.3	553.4	553.5	562.3	**515.9**	556.4
Heavy Crude Oil	**127.3**	224.7	214.2	226.3	218.7	**197.9**	219.6
Light/Medium Crude Oil	**225.3**	380.6	339.2	327.2	343.6	**318.0**	336.8
Crude Unit Utilization [4] (percent)	**97**	99	90	90	92	**94**	91
Total Refined Product Production (Mbbls/d)							
Gasoline	**200.6**	304.7	277.1	284.7	301.8	**266.7**	280.5
Distillates [5]	**132.6**	233.4	206.8	208.8	216.2	**195.3**	209.1
Asphalt	**17.5**	28.2	24.3	25.7	29.1	**23.9**	28.3
Other	**45.5**	81.7	92.2	76.7	57.1	**74.0**	72.1
Total Refined Product Production (Mbbls/d)	**396.2**	648.0	600.4	595.9	604.2	**559.9**	590.0
Adjusted Refining Margin [1] ($/bbl)	**18.17**	15.92	12.57	8.41	5.98	**13.44**	11.83
Weighted Average Crack Spread, Net of RINs (US$/bbl)	**12.29**	17.81	15.80	9.46	8.20	**13.85**	13.01
Weighted Average Crack Spread, Net of RINs (C$/bbl)	**17.14**	24.53	21.86	13.58	11.47	**19.34**	17.82
Adjusted Market Capture [1] (percent)	**106**	65	58	62	52	**69**	67
Operating Expenses	**413**	611	806	716	718	**2,546**	2,763
Operating Expenses - Excluding Turnaround Costs	**399**	573	568	635	590	**2,176**	2,457
Operating Expenses - Turnaround Costs	**14**	38	238	81	128	**370**	306
Per-Unit Operating Expenses [3] ($/bbl)	**11.96**	10.32	14.92	13.69	13.26	**12.73**	12.99
Per-Unit Operating Expenses - Excluding Turnaround Costs	**11.57**	9.67	10.52	12.15	10.89	**10.88**	11.55
Per-Unit Operating Expenses - Turnaround Costs	**0.39**	0.65	4.40	1.54	2.37	**1.85**	1.44

(1) Contains a non-GAAP financial measure. See the Specified Financial Measures Advisory of this Supplemental.

(2) In the Canadian Refining segment, operating expenses represent expenses associated with the Lloydminster Upgrader, the Lloydminster Refinery and the commercial fuels business.

(3) Specified financial measure. See the Specified Financial Measures Advisory of this Supplemental.

(4) On September 30, 2025, the Company completed the divestiture of our entire 50 percent interest in the Wood River and Borger refinery operations held through WRB Refining LP ("WRB"). For the twelve months ended December 31, 2025, reported operable capacity and crude unit utilization reflect the weighted average impact of the WRB divestiture.

(5) Includes diesel and jet fuel.

SUPPLEMENTAL INFORMATION *(unaudited)*

Advisory

Specified Financial Measures

Certain financial measures, including non-GAAP financial measures, in this document do not have a standardized meaning prescribed by International Financial Reporting Standards as issued by the International Accounting Standards Board (the "IFRS Accounting Standards"), and are considered specified financial measures. These specified financial measures may not be comparable to similar measures presented by other issuers. Commencing March 31, 2025, we have replaced our definitions of Refining Margin and Market Capture with Adjusted Refining Margin and Adjusted Market Capture, respectively, which excludes the impact of inventory holding gains or losses. These gains or losses reflect the difference between the cost of volumes produced at current-period costs and the cost of volumes produced under the first-in, first-out or weighted average cost basis, as required by IFRS Accounting Standards.

For information incorporated by reference about Cenovus's specified financial measures, including the replaced metrics above, see the Specified Financial Measures Advisory and our Management's Discussion and Analysis for the periods ended September 30, 2025, June 30, 2025, and March 31, 2025 (available on SEDAR+ at sedarplus.ca).

ADVISORY

Oil and Gas Information

Barrels of Oil Equivalent – natural gas volumes are converted to BOE on the basis of six Mcf to one bbl. BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil compared with natural gas is significantly different from the energy equivalency conversion ratio of 6:1, utilizing a conversion on a 6:1 basis is not an accurate reflection of value.

Interests in Joint Ventures

Cenovus holds interests in a number of joint ventures, as classified under IFRS Accounting Standards, that are accounted for using the equity method of accounting in our Consolidated Financial Statements, including a 30 percent equity ownership interest in Duvernay and a 40 percent equity ownership interest in HCML. Unless otherwise indicated, the operational events and results from these equity interests including, without limitation, production, reserves, revenues, costs and expenses may not be reflected in the Consolidated Financial Statements or the MD&A. As a result, the disclosure in the AIF in respect to certain equity method investees may differ from corresponding information in the MD&A. Readers are directed to the information contained under the heading "Reserves Data and Other Oil and Gas Information" in the AIF for further information regarding Cenovus's interests in Duvernay and HCML.

Forward-looking Information

This document contains forward-looking statements and other information (collectively "forward-looking information") about the Company's current expectations, estimates and projections, made in light of the Company's experience and perception of historical trends. Although the Company believes that the expectations represented by such forward-looking information are reasonable, there can be no assurance that such expectations will prove to be correct.

This forward-looking information is identified by words such as "advance", "aim", "allocate", "anticipate", "believe", "commit", "continue", "could", "deliver", "expect", "F", "focus", "grow", "maintain", "may", "maximize", "mitigate", "on track", "objective", "ongoing", "opportunities", "optimize", "plan", "position", "potential", "priority", "progress", "strategy", "steward", "strive", "target", and "will", or similar expressions and includes suggestions of future outcomes, including, but not limited to, statements about: our five strategic objectives; shareholder value and returns; top-tier safety performance; safety priorities; sustainability leadership and progressing sustainability initiatives; focus on cost leadership and balancing shareholder returns with deleveraging; our commitment to the Pathways Alliance foundational project, including efforts to reach agreements with governments; maximizing value and profitability; disciplined capital allocation; cash flow and commodity price volatility and stability; price alignment and volatility management strategies; dividends; focus on cost and sustainability improvements; liquidity; our 2026 corporate guidance; factors influencing commodity outlook; the Company's key priorities for 2026; the impact of the global trade war; realizing the full value of our integrated strategy; capitalizing on opportunities; Net Debt targets pursuant to the shareholder returns framework; allocating Excess Free Funds Flow to shareholder returns; absolute and per share Free Funds Flow growth; project execution; growing our competitive advantages in our heavy oil value chain and reliable operations; monitoring market fundamentals and optimizing run rates at our refineries; safe and reliable operations; being best-in-class operators; maintaining a strong balance sheet; costs; margins; long-term value for Cenovus; progressing hookup and commissioning of the platform at the West White Rose project; progressing growth projects, including the Amine Claus project at Foster Creek, the Christina Lake North expansion project, the Sunrise growth program and the development of our Lloydminster assets; our sustainability focus areas, goals, plans and commitments; provision for income taxes; funding near-term cash requirements; credit ratings; meeting payment obligations; general outlook for crude oil and refined product prices; price volatility and geopolitical risks; impact of current and future economic arrangements between Canada and the U.S. including tariffs and other measures and countermeasures and responses thereto on market access and transportation; the use of derivatives, financial instruments and physical positions as financial risk management activities; trading activities, including trading of energy products, for purposes other than hedging Net Debt to Adjusted Funds Flow ratio; the Company's capital allocation framework; Net Debt to Adjusted EBITDA ratio; Net Debt to Capitalization ratio; introduction of artificial intelligence pilot-phase; maintaining sufficient liquidity; financial resilience; liabilities from legal proceedings; transportation and storage commitments; and the Company's outlook for commodities and the Canadian dollar, the factors that affect such outlook, and the influences and effects on Cenovus.

Readers are cautioned not to place undue reliance on forward-looking information as the Company's actual results may differ materially from those expressed or implied. Developing forward-looking information involves reliance on a number of assumptions and consideration of certain risks and uncertainties, some of which are specific to the Company and others that apply to the industry generally. The factors or assumptions on which the forward-looking information is based include, but are not limited to: forecast bitumen, crude oil and natural gas, NGLs, condensate and refined products prices, and light-heavy and light-medium crude oil price differentials; the Company's ability to realize the anticipated benefits of acquisitions; the accuracy of any assessments undertaken in connection with acquisitions; forecast production and crude throughput volumes and timing

thereof; forecast prices and costs, projected capital investment levels, the flexibility of capital spending plans and associated sources of funding; the absence of significant adverse changes to government policies, legislation and regulations (including related to climate change Indigenous relations, title or rights claims, royalty regimes, interest rates, inflation, foreign exchange rates, global economic activity, competitive conditions, trade sanctions, restrictive trade measures or countermeasures, and the supply and demand for bitumen, crude oil and natural gas, NGLs, condensate and refined products and the political, economic and social stability of jurisdictions in which the Company operates; the absence of significant disruption of operations, including as a result of harsh weather, natural disaster, accident, third-party actions, civil unrest or other similar events; the prevailing climatic conditions in the Company's operating locations; achievement of further cost reductions and sustainability thereof; applicable royalty regimes, including expected royalty rates; future improvements in availability of product transportation capacity; increase to the Company's share price and market capitalization over the long-term; opportunities to purchase shares for cancellation at prices acceptable to the Company; the Company's ability to use financial risk management activities and physical positions to manage its exposure to fluctuations in commodity prices and, foreign exchange and interest rates, optimize supply costs or sales of production; the Company's ability to use fixed-price commitments for the purchase or sale of commodities; the sufficiency of cash balances, internally generated cash flows, existing credit facilities, management of the Company's asset portfolio and access to capital and insurance coverage to pursue and fund future investments and development plans and dividends, including any increase thereto; realization of expected capacity to store within the Company's oil sands reservoirs barrels not yet produced, including that the Company will be able to time production and sales of its inventory at later dates when demand has increased, pipeline and/or storage capacity has improved and future crude oil differentials have narrowed; the WTI-WCS differential in Alberta remains largely tied to global supply factors and heavy crude oil processing capacity, as long as supply does not exceed Canadian crude oil export capacity; the Company's ability to produce from oil sands facilities on an unconstrained basis; estimates of quantities of oil, bitumen, NGLs from properties and other sources not currently classified as proved; the accuracy of accounting estimates and judgments; the Company's ability to obtain necessary regulatory and partner approvals; the successful, timely and cost effective implementation of capital projects, development projects or stages thereof; the Company's ability to meet current and future obligations; estimated abandonment and reclamation costs, including associated levies and regulations applicable thereto; the Company's ability to obtain and retain qualified staff and equipment in a timely and cost-efficient manner; the Company's ability to complete acquisitions and divestitures, including with desired transaction metrics and within expected timelines; the accuracy of climate scenarios and assumptions, including third-party data on which the Company relies; ability to access and implement all technology and equipment necessary to achieve expected future results, including in respect of sustainability targets and the Pathways Alliance project, and the commercial viability and scalability of related technology and products; expected benefits of investments in sustainability focus areas; collaboration with the government, Pathways Alliance and other industry organizations; market and business conditions; forecast inflation and other assumptions inherent in the Company's 2026 guidance available on cenovus.com and as set out below; and other risks and uncertainties described from time to time in the filings the Company makes with securities regulatory authorities.

2026 guidance dated December 10, 2025, and available on cenovus.com, assumes: Brent prices of US$64.00 per barrel, WTI prices of US$60.00 per barrel; WCS of US$47.50 per barrel; Differential WTI-WCS of US$12.50 per barrel; AECO natural gas prices of $2.50 per Mcf; Chicago 3-2-1 crack spread of US$20.00 per barrel; RINs of US$6.00 per barrel; and an exchange rate of $0.72 US$/C$.

The risk factors and uncertainties that could cause the Company's actual results to differ materially from the forward-looking information, include, but are not limited to: the Company's ability to realize the anticipated benefits of acquisitions in a timely manner or at all; the Company's ability to successfully integrate acquired business with its own in a timely and cost effective manner or at all; unforeseen or underestimated liabilities associated with acquisitions; risks associated with acquisitions and divestitures; the Company's ability to access or implement some or all of the technology necessary to efficiently and effectively operate its assets and achieve expected future results including in respect of sustainability targets and the Pathways Alliance project and the commercial viability and scalability of related technology and products; the effect of new significant shareholders; volatility of and other assumptions regarding commodity prices; the duration and impact of any market downturn; the Company's ability to integrate upstream and downstream operations to help mitigate the impact of volatility in light-heavy crude oil differentials and contribute to its net earnings; foreign exchange risk, including related to agreements denominated in foreign currencies; the Company's continued liquidity being sufficient to sustain operations through a prolonged market downturn; WTI-WCS differential at Hardisty does not remain largely tied to global supply factors and heavy crude processing capacity; the Company's ability to realize the expected impacts of its capacity to store within its oil sands reservoirs barrels not yet produced, including possible inability to time production and sales at later dates when pipeline and/or storage capacity and crude oil differentials have improved; the effectiveness of the Company's risk management program; the accuracy of the Company's outlook for commodity prices and currency and interest rates; changes in laws or enforcement of existing laws, exchange rate fluctuations, trade disputes, trade agreements or treaties, new or increased tariffs, economic sanctions and other restrictive trade measures or countermeasures, and responses thereto; product supply and demand; the accuracy of the Company's share price and market capitalization assumptions; market competition, including from alternative energy sources; risks inherent in the Company's marketing operations, including credit risks, exposure to counterparties and partners, including the ability and willingness of such parties to satisfy contractual obligations in a timely manner; risks inherent

in the operation of the Company's crude-by-rail terminal, including health, safety and environmental risks; the Company's ability to maintain desirable ratios of Net Debt to Adjusted EBITDA and Net Debt to Adjusted Funds Flow; the Company's ability to access various sources of debt and equity capital, generally, and on acceptable terms; the Company's ability to finance growth and sustaining capital expenditures; the ability to complete and optimize drilling, completion, tie in and infrastructure projects; the ability of the Company to ramp-up activities at its refineries on its anticipated timelines; changes in credit ratings applicable to the Company or any of its securities; changes to the Company's dividend plans; the Company's ability to utilize tax losses in the future; tax audits and reassessments; the accuracy of the Company's reserves, future production and future net revenue estimates; the accuracy of factors influencing decisions on the priority and timing of development of undeveloped reserves; potential disruptions and risks associated with the adoption, development and integration of AI; the accuracy of the Company's accounting estimates and judgements; the Company's ability to replace and expand crude oil and natural gas reserves; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project developments; potential requirements under applicable accounting standards for impairment or reversal of estimated recoverable amounts of some or all of the Company's assets or goodwill from time to time; the Company's ability to maintain its relationships with its partners and to successfully manage and operate its integrated operations and business; reliability of the Company's assets including in order to meet production targets; potential disruption or unexpected technical difficulties in developing new products and refining processes; the occurrence of unexpected events resulting in operational interruptions, including at facilities operated by our partners or third parties, such as blowouts, fires, explosions, railcar incidents or derailments, aviation incidents, iceberg collisions, gaseous leaks, migration of harmful substances, loss of containment, releases or spills, including releases or spills from offshore facilities and shipping vessels at terminals or hubs and as a result of pipeline or other leaks, corrosion, epidemics and pandemics; and catastrophic events, including, but not limited to, war, adverse sea conditions, extreme weather events, natural disasters, acts of activism, vandalism and terrorism, and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites and other accidents or similar events; refining and marketing margins; cost escalations, including inflationary pressures on operating costs, such as labour, materials, natural gas and other energy sources used in oil sands processes and downstream operations and increased insurance deductibles or premiums; the cost and availability of equipment necessary to the Company's operations; potential failure of products to achieve or maintain acceptance in the market; risks associated with the energy industry's and the Company's reputation, social licence to operate and litigation related thereto; legal challenges or opposition to infrastructure projects associated with Indigenous title or other rights claims; unexpected cost increases or technical difficulties in operating, constructing or modifying refining or refining facilities; unexpected difficulties in producing, transporting or refining bitumen and/or crude oil into petroleum and chemical products; risks associated with technology and equipment and its application to the Company's business, including potential cyberattacks; geo-political and other risks associated with the Company's international operations; risks associated with climate change and the Company's assumptions relating thereto; the timing and the costs of well and pipeline construction; the Company's ability to access markets and to secure adequate and cost effective product transportation including sufficient pipeline, crude-by-rail, marine or alternate transportation, including to address any gaps caused by constraints in the pipeline system or storage capacity; availability of, and the Company's ability to attract and retain, critical talent and integrate new personnel acquired in transactions; possible failure to obtain and retain qualified leadership and personnel, and equipment in a timely and cost efficient manner; changes in labour demographics and relationships, including with any unionized workforces; unexpected abandonment and reclamation costs; changes in the regulatory frameworks, permits and approvals in any of the locations in which the Company operates or to any of the infrastructure upon which it relies; climate change-related regulatory, climactic transition risks; failure to achieve our sustainability goals, or a perception among key stakeholders that our actions or goals are insufficient or unattainable; government actions or regulatory initiatives to curtail energy operations or pursue broader climate change agendas; changes to regulatory approval processes and land use designations, royalty, tax, environmental, GHG, carbon, climate change and other laws or regulations, or changes to the interpretation of such laws and regulations, as adopted or proposed, the impact thereof and the costs associated with compliance; the expected impact and timing of various accounting pronouncements, rule changes and standards on the Company's business, its financial results and Consolidated Financial Statements; changes in general economic, market and business conditions; OPEC+ policy; actions of OPEC and non-OPEC members, including compliance or non-compliance with agreed upon quotas and decisions to impose production quotas; the political, social and economic conditions in the jurisdictions in which the Company operates or supplies; the status of the Company's relationships with the communities in which it operates, including with Indigenous communities; the occurrence of unexpected events such as protests, pandemics, war, terrorist threats and the instability resulting therefrom; and risks associated with existing and potential future lawsuits, shareholder proposals and regulatory actions against the Company. In addition, there are risks that the effect of actions taken by us in attempting to achieve goals for sustainability focus areas may have a negative impact on our existing business, growth plans and future results from operations, or that the benefits may be less than expected.

Except as required by applicable securities laws, Cenovus disclaims any intention or obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that the foregoing lists are not exhaustive and are made as at the date hereof. Events or circumstances could cause our actual results to differ materially from those estimated or projected and expressed in, or implied by, the forward-looking information. For a full discussion of the Company's material risk factors, see Risk Management and Risk Factors in the Company's most recently filed Annual MD&A, and the risk factors described in other documents the Company files from time to time with securities regulatory authorities in Canada, available on SEDAR+ at sedarplus.ca, and with the U.S. Securities and Exchange Commission on EDGAR at sec.gov, and on the Company's website at cenovus.com.

Information on or connected to the Company's website at cenovus.com does not form part of the MD&A unless expressly incorporated by reference herein.

ABBREVIATIONS AND DEFINITIONS

Abbreviations

The following abbreviations and definitions are used in this document:

Crude Oil and NGLs		Natural Gas		Other	
bbl	barrel	Mcf	thousand cubic feet	BOE	barrel of oil equivalent
Mbbls/d	thousand barrels per day	MMcf	million cubic feet	MBOE/d	thousand barrels of oil equivalent per day
MMbbls	million barrels	MMcf/d	million cubic feet per day	MMBOE	million barrels of oil equivalent
WCS	Western Canadian Select	Bcf	billion cubic feet	DD&A	depreciation, depletion and amortization
WTI	West Texas Intermediate			GHG	greenhouse gas
				FPSO	floating production, storage and offloading unit
				NCIB	normal course issuer bid
				AECO	Alberta Energy Company
				NYMEX	New York Mercantile Exchange
				OPEC	Organization of Petroleum Exporting Countries
				OPEC+	OPEC and a group of 11 non-OPEC members
				USGC	U.S. Gulf Coast

SPECIFIED FINANCIAL MEASURES

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS Accounting Standards including Operating Margin, Operating Margin by asset, Adjusted Funds Flow, Adjusted Funds Flow Per Share – Basic, Adjusted Funds Flow Per Share – Diluted, Free Funds Flow, Excess Free Funds Flow, Total Long-Term Liabilities, Realized Sales Price, Conventional, Offshore and Asia Pacific Per-Unit Operating Expenses, Netbacks (including the total Netback per BOE), Gross Margin, Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture.

These measures may not be comparable to similar measures presented by other issuers. These measures are described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation, or as a substitute for, measures prepared in accordance with IFRS Accounting Standards. The definition and reconciliation, if applicable, of each specified financial measure is presented in this Advisory and may also be presented in the Operating and Financial Results section of the MD&A. Refer to the Specified Financial Measures Advisory of the relevant period's MD&A for reconciliations of Operating Margin, Adjusted Funds Flow, Free Funds Flow and Excess Free Funds Flow for prior period information from 2025, 2024 and 2023 that is not found below.

Non-GAAP Financial Measures and Non-GAAP Ratios

Operating Margin

Operating Margin and Operating Margin by asset are non-GAAP financial measures, and Operating Margin for upstream or downstream operations are specified financial measures. These are used to provide a consistent measure of the cash-generating performance of our operations and assets for comparability of our underlying financial performance between periods. Operating Margin is defined as revenues less purchased product, transportation and blending expenses, operating expenses, plus realized gains less realized losses on risk management activities. Items within the Corporate and Eliminations segment are excluded from the calculation of Operating Margin. The following tables provide a reconciliation to our Consolidated Financial Statements.

Operating Margin

	Three Months Ended December 31,					
	2025	2024	**2025**	2024	**2025**	2024
($ millions)	**Upstream** [1]		**Downstream** [1]		**Total**	
Gross Sales						
External Sales	**6,373**	6,050	**5,180**	7,677	**11,553**	13,727
Intersegment Sales	**1,914**	2,190	**134**	160	**2,048**	2,350
	8,287	8,240	**5,314**	7,837	**13,601**	16,077
Royalties	**(670)**	(914)	**—**	—	**(670)**	(914)
Revenues	**7,617**	7,326	**5,314**	7,837	**12,931**	15,163
Expenses						
Purchased Product	**1,271**	1,000	**4,574**	7,364	**5,845**	8,364
Transportation and Blending	**2,832**	2,816	**—**	—	**2,832**	2,816
Operating	**893**	842	**591**	866	**1,484**	1,708
Realized (Gain) Loss on Risk Management	**(7)**	(2)	**—**	3	**(7)**	1
Operating Margin	**2,628**	2,670	**149**	(396)	**2,777**	2,274

(1) Found in Note 1 of the interim Consolidated Financial Statements.

	Year Ended December 31,					
	2025	2024	**2025**	2024	**2025**	2024
($ millions)	**Upstream [1]**		**Downstream [1]**		**Total**	
Gross Sales						
External Sales	**24,354**	24,640	**28,397**	33,086	**52,751**	57,726
Intersegment Sales	**8,141**	8,438	**800**	532	**8,941**	8,970
	32,495	33,078	**29,197**	33,618	**61,692**	66,696
Royalties	**(3,055)**	(3,449)	**—**	—	**(3,055)**	(3,449)
Revenues	**29,440**	29,629	**29,197**	33,618	**58,637**	63,247
Expenses						
Purchased Product	**4,223**	3,674	**25,855**	30,252	**30,078**	33,926
Transportation and Blending	**11,243**	11,331	**—**	—	**11,243**	11,331
Operating	**3,567**	3,489	**3,143**	3,670	**6,710**	7,159
Realized (Gain) Loss on Risk Management	**4**	14	**(6)**	8	**(2)**	22
Operating Margin	**10,403**	11,121	**205**	(312)	**10,608**	10,809

(1) Found in Note 1 of the Consolidated Financial Statements.

Operating Margin by Asset

	Year Ended December 31, 2025		
($ millions)	**Atlantic**	**Asia Pacific**	**Offshore [1]**
Gross Sales	**420**	**1,088**	**1,508**
Royalties	**(4)**	**(76)**	**(80)**
Revenues	**416**	**1,012**	**1,428**
Expenses			
Purchased Product	**—**	**—**	**—**
Transportation and Blending	**17**	**—**	**17**
Operating	**226**	**123**	**349**
Operating Margin	**173**	**889**	**1,062**

	Year Ended December 31, 2024		
($ millions)	Atlantic	Asia Pacific	Offshore [1]
Gross Sales	322	1,250	1,572
Royalties	(2)	(97)	(99)
Revenues	320	1,153	1,473
Expenses			
Purchased Product	—	—	—
Transportation and Blending	11	—	11
Operating	290	133	423
Operating Margin	19	1,020	1,039

(1) Found in Note 1 of the Consolidated Financial Statements.

Adjusted Funds Flow, Free Funds Flow and Excess Free Funds Flow

Adjusted Funds Flow is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring a company's ability to finance its capital programs and meet its financial obligations, in total and on a per-share basis. Adjusted Funds Flow is defined as cash from (used in) operating activities, excluding settlement of decommissioning liabilities and net change in operating non-cash working capital. Operating non-cash working capital is composed of accounts receivable and accrued revenues, income tax receivable, inventories (excluding non-cash inventory write-downs and reversals), accounts payable and accrued liabilities, and income tax payable. Adjusted Funds Flow Per Share – Basic is defined as Adjusted Funds Flow divided by the basic weighted average number of shares. Adjusted Funds Flow Per Share – Diluted is defined as Adjusted Funds Flow divided by the diluted weighted average number of shares.

Free Funds Flow is a non-GAAP financial measure used to assist in measuring the available funds the Company has after financing its capital programs. Free Funds Flow is defined as cash from (used in) operating activities, excluding settlement of decommissioning liabilities and net change in operating non-cash working capital, minus capital investment.

Excess Free Funds Flow is a non-GAAP financial measure used by the Company to deliver shareholder returns and allocate capital according to our shareholder returns and capital allocation framework. Excess Free Funds Flow is defined as Free Funds Flow minus base dividends paid on common shares, dividends paid on preferred shares, net purchases of common shares under the employee benefit plan, other uses of cash (including settlement of decommissioning liabilities and principal repayment of leases), and expenditures for acquisitions net of cash acquired, plus proceeds from, or payments related to, divestitures.

	Three Months Ended December 31,		Year Ended December 31,	
($ millions)	**2025**	2024	**2025**	2024
Cash From (Used in) Operating Activities	**2,408**	2,029	**8,228**	9,235
(Add) Deduct:				
Settlement of Decommissioning Liabilities	**(82)**	(64)	**(280)**	(234)
Net Change in Non-Cash Working Capital	**(184)**	492	**(363)**	1,305
Adjusted Funds Flow	**2,674**	1,601	**8,871**	8,164
Capital Investment	**1,360**	1,478	**4,907**	5,015
Free Funds Flow	**1,314**	123	**3,964**	3,149
Add (Deduct):				
Base Dividends Paid on Common Shares	**(376)**	(330)	**(1,423)**	(1,255)
Dividends Paid on Preferred Shares	**(4)**	(18)	**(14)**	(45)
Purchase of Common Shares Under Employee Benefit Plan	**(61)**	(43)	**(155)**	(43)
Settlement of Decommissioning Liabilities	**(82)**	(64)	**(280)**	(234)
Principal Repayment of Leases	**(84)**	(80)	**(350)**	(299)
Acquisitions, Net of Cash Acquired	**(3,430)**	(3)	**(3,666)**	(22)
Acquisition of Ownership Interest in MEG Energy Corp. (1)	**(752)**	—	**(752)**	—
Proceeds From Divestitures	**1,878**	(1)	**1,891**	46
Excess Free Funds Flow	**(1,597)**	(416)	**(785)**	1,297

(1) Represents the acquired MEG common shares purchased prior to the closing of the MEG Acquisition. For further information, refer to Note 3 of the interim Consolidated Financial Statements.

Total Long-Term Liabilities

Total Long-Term Liabilities is a non-GAAP financial measure. The measure is disclosed to fulfill the requirements of National Instrument 51-102, *"Continuous Disclosure Obligations"* and is defined as total liabilities less total current liabilities.

	As at December 31,		
($ millions)	**2025**	2024	2023
Total Liabilities	**31,786**	26,770	25,203
Less: Total Current Liabilities	**6,314**	7,362	6,210
Total Long-Term Liabilities	**25,472**	19,408	18,993

Gross Margin, Adjusted Gross Margin, Adjusted Refining Margin and Adjusted Market Capture

Gross Margin and Adjusted Gross Margin are non-GAAP financial measures that are used to evaluate the performance of our downstream operations. We define Gross Margin as revenues less purchased product and Adjusted Gross Margin as revenues less purchased product, excluding the impact of inventory holding gains or losses.

Inventory holding gains or losses reflects the difference between the cost of volumes produced at current-period costs, which is an indication of current market conditions, and the cost of volumes produced under the FIFO or weighted average cost basis as required by IFRS Accounting Standards, which generally reflects the market conditions at the time feedstock was purchased. The purchase and sale of inventories creates a timing difference that could be anywhere from several weeks to several months. This measure is an estimate of the impact of current-period costs to FIFO or weighted average cost, and assumes that all opening volumes are sold in the current period. Cenovus uses inventory holding gains or losses to analyze the performance of our assets and increase comparability with refining peers.

Adjusted Refining Margin and Adjusted Market Capture contain non-GAAP financial measures. Adjusted Refining Margin is used to evaluate our downstream operations after adjusting for inventory holding gains or losses. Adjusted Market Capture is used in our U.S. Refining segment to provide an indication of margin captured relative to what was available in the market based on widely-used benchmarks. These measures are useful to consistently measure the performance of our downstream operations.

We define Adjusted Refining Margin as Adjusted Gross Margin divided by total processed inputs and Adjusted Market Capture as Adjusted Refining Margin divided by the weighted average 3-2-1 market benchmark crack, net of RINs, expressed as a percentage. The weighted average crack spread, net of RINs, is calculated on Cenovus's operable capacity-weighted average of the Chicago and Group 3 3-2-1 benchmark market crack spreads, net of RINs.

We previously disclosed Refining Margin and Market Capture, which did not exclude the effect of inventory holding gains or losses. As of March 31, 2025, we have added Adjusted Gross Margin, and replaced our definitions of Refining Margin and Market Capture to exclude the impact of inventory holding gains or losses. We believe these changes provide more comparability and accuracy when measuring the performance of our downstream operations.

Comparative period information has been provided below for these new metrics.

Canadian Refining

	Three Months Ended December 31, 2025		
($ millions, except where indicated)	**Lloydminster Upgrader and Lloydminster Refinery Total**	**Other [1]**	**Total Canadian Refining [2]**
Revenues	**1,078**	**78**	**1,156**
Purchased Product	**862**	**48**	**910**
Gross Margin	**216**	**30**	**246**
Add (Deduct):			
Inventory Holding (Gain) Loss	**4**	**—**	**4**
Adjusted Gross Margin	**220**	**30**	**250**
Total Processed Inputs (Mbbls/d)	**122.6**		
Adjusted Refining Margin ($/bbl)	**19.57**		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

	Three Months Ended December 31, 2024		
($ millions, except where indicated)	Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	1,207	56	1,263
Purchased Product	1,032	36	1,068
Gross Margin	175	20	195
Add (Deduct):			
Inventory Holding (Gain) Loss	—	—	—
Adjusted Gross Margin	175	20	195
Total Processed Inputs (Mbbls/d)	112.1		
Adjusted Refining Margin ($/bbl)	16.96		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the interim Consolidated Financial Statements.

($ millions, except where indicated)	Year Ended December 31, 2025 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	**4,781**	**298**	**5,079**
Purchased Product	**3,932**	**196**	**4,128**
Gross Margin	**849**	**102**	**951**
Add (Deduct):			
Inventory Holding (Gain) Loss	**3**	**—**	**3**
Adjusted Gross Margin	**852**	**102**	**954**
Total Processed Inputs (Mbbls/d)	**119.4**		
Adjusted Refining Margin ($/bbl)	**19.57**		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the Consolidated Financial Statements.

($ millions, except where indicated)	Year Ended December 31, 2024 Lloydminster Upgrader and Lloydminster Refinery Total	Other [1]	Total Canadian Refining [2]
Revenues	5,014	296	5,310
Purchased Product	4,278	205	4,483
Gross Margin	736	91	827
Add (Deduct):			
Inventory Holding (Gain) Loss	(4)	2	(2)
Adjusted Gross Margin	732	93	825
Total Processed Inputs (Mbbls/d)	96.6		
Adjusted Refining Margin ($/bbl)	20.72		

(1) Includes ethanol operations and crude-by-rail operations.
(2) Revenues and purchased product are found in Note 1 of the Consolidated Financial Statements.

U.S. Refining

($ millions, except where indicated)	Three Months Ended December 31, 2025	Three Months Ended December 31, 2024	Year Ended December 31, 2025	Year Ended December 31, 2024
Revenues [1]	**4,158**	6,574	**24,118**	28,308
Purchased Product [1]	**3,664**	6,296	**21,727**	25,769
Gross Margin	**494**	278	**2,391**	2,539
Add (Deduct):				
Inventory Holding (Gain) Loss	**134**	45	**298**	(23)
Adjusted Gross Margin	**628**	323	**2,689**	2,516
Total Processed Inputs (Mbbls/d)	**375.8**	588.4	**548.1**	581.4
Adjusted Refining Margin ($/bbl)	**18.17**	5.98	**13.44**	11.83
Operable Capacity [2] (Mbbls/d)	**364.8**	612.3	**549.9**	612.3
Operable Capacity by Regional Benchmark (percent)				
Chicago 3-2-1 Crack Spread Weighting	**88**	81	**82**	81
Group 3 3-2-1 Crack Spread Weighting	**12**	19	**18**	19
Benchmark Prices and Exchange Rate				
Chicago 3-2-1 Crack Spread (US$/bbl)	**18.20**	12.12	**19.44**	16.74
Group 3 3-2-1 Crack Spread (US$/bbl)	**19.25**	12.66	**20.63**	16.81
RINs (US$/bbl)	**6.04**	4.02	**5.81**	3.74
US$ per C$1 – Average	**0.717**	0.715	**0.716**	0.730
Weighted Average Crack Spread, Net of RINs ($/bbl)	**17.14**	11.47	**19.34**	17.82
Adjusted Market Capture (percent)	**106**	52	**69**	67

(1) Found in Note 1 of the interim Consolidated Financial Statements.
(2) For the year ended December 31, 2025, reported operable capacity reflects the weighted average impact of the WRB Divestiture, which closed on September 30, 2025.

Netback Reconciliations and Realized Sales Price

Netback is a non-GAAP financial measure commonly used in the oil and gas industry to assist in measuring operating performance. Our Netback calculation is substantially aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook. Netback is defined as gross sales less royalties, transportation and blending, and operating expenses. Netbacks do not reflect non-cash write-downs or reversals of product inventory until it is realized when the product is sold and exclude risk management activities. Condensate or butane (diluent) is blended with crude oil to transport it to market. Netback per barrel of oil equivalent contains a non-GAAP measure. Netbacks per barrel of oil equivalent reflect our margin on a per-barrel of oil equivalent basis. Per-unit measures are divided by sales volumes.

Realized Sales Price contains a non-GAAP measure. It includes our gross sales, purchased diluent costs and profit from optimization activities, such as cogeneration, third-party processing and trading. Conventional, Offshore and Asia Pacific Per-Unit Operating Expenses contain non-GAAP measures. As of March 31, 2025, modifications were made to our Conventional Netback to include our 30 percent equity interest in the Duvernay joint venture. These modifications resulted in minor adjustments that are captured in the netback calculation on a prospective basis. Offshore and Asia Pacific operating expenses, as used in the basis of our Netback calculations, reflect our 40 percent equity interest in the HCML joint venture. The Duvernay and HCML joint ventures are accounted for using the equity method in the interim Consolidated Financial Statements.

The following tables provide a reconciliation of Netback to Operating Margin found in our interim Consolidated Financial Statements.

Oil Sands

Three Months Ended December 31, 2025 ($ millions)	Basis of Netback Calculation				
	Foster Creek	**Christina Lake**	**Sunrise**	**Lloydminster [1]**	**Total Oil Sands [2]**
Gross Sales	1,439	1,752	377	762	**4,330**
Royalties	(231)	(337)	(20)	(92)	**(680)**
Revenues	1,208	1,415	357	670	**3,650**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	228	224	77	37	**566**
Operating	183	253	85	224	**745**
Netback	797	938	195	409	**2,339**
Realized (Gain) Loss on Risk Management					**(2)**
Operating Margin					**2,341**

Three Months Ended December 31, 2025 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [2]	**Condensate**	**Third-party Sourced**	**Other [3]**	**Total Oil Sands [4]**
Gross Sales	**4,330**	2,180	827	(125)	**7,212**
Royalties	**(680)**	—	—	41	**(639)**
Revenues	**3,650**	2,180	827	(84)	**6,573**
Expenses					
Purchased Product	**—**	—	827	64	**891**
Transportation and Blending	**566**	2,180	—	(9)	**2,737**
Operating	**745**	—	—	(23)	**722**
Netback	**2,339**	—	—	(116)	**2,223**
Realized (Gain) Loss on Risk Management	**(2)**	—	—	—	**(2)**
Operating Margin	**2,341**	—	—	(116)	**2,225**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.
(3) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation, as well as adjustments to reflect the cost of volumes produced on acquired inventory.
(4) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended December 31, 2024 ($ millions)	Basis of Netback Calculation				
	Foster Creek	**Christina Lake**	**Sunrise**	**Lloydminster [1]**	**Total Oil Sands [2]**
Gross Sales	1,454	1,646	380	871	**4,351**
Royalties	(283)	(455)	(19)	(117)	**(874)**
Revenues	1,171	1,191	361	754	**3,477**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	281	137	59	44	**521**
Operating	163	187	72	200	**622**
Netback	727	867	230	510	**2,334**
Realized (Gain) Loss on Risk Management					**(3)**
Operating Margin					**2,337**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.

Three Months Ended December 31, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [1]	Condensate	Third-party Sourced	Other [2]	Total Oil Sands [3]
Gross Sales	**4,351**	2,181	465	94	**7,091**
Royalties	**(874)**	—	—	—	**(874)**
Revenues	**3,477**	2,181	465	94	**6,217**
Expenses					
Purchased Product	**—**	—	465	65	**530**
Transportation and Blending	**521**	2,181	—	33	**2,735**
Operating	**622**	—	—	(7)	**615**
Netback	**2,334**	—	—	3	**2,337**
Realized (Gain) Loss on Risk Management	**(3)**	—	—	—	**(3)**
Operating Margin	**2,337**	—	—	3	**2,340**

(1) Includes bitumen and heavy oil.
(2) Other includes construction, transportation and blending.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Year Ended December 31, 2025 ($ millions)	Basis of Netback Calculation				
	Foster Creek	Christina Lake	Sunrise	Lloydminster [1]	Total Oil Sands [2]
Gross Sales	5,938	6,252	1,479	3,247	**16,916**
Royalties	(1,093)	(1,414)	(73)	(379)	**(2,959)**
Revenues	4,845	4,838	1,406	2,868	**13,957**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	1,090	638	301	149	**2,178**
Operating	741	763	342	926	**2,772**
Netback	3,014	3,437	763	1,793	**9,007**
Realized (Gain) Loss on Risk Management					**8**
Operating Margin					**8,999**

Year Ended December 31, 2025 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [2]	Condensate	Third-party Sourced	Other [3]	Total Oil Sands [4]
Gross Sales	**16,916**	8,636	2,578	197	**28,327**
Royalties	**(2,959)**	—	—	39	**(2,920)**
Revenues	**13,957**	8,636	2,578	236	**25,407**
Expenses					
Purchased Product	**—**	—	2,578	308	**2,886**
Transportation and Blending	**2,178**	8,636	—	61	**10,875**
Operating	**2,772**	—	—	(18)	**2,754**
Netback	**9,007**	—	—	(115)	**8,892**
Realized (Gain) Loss on Risk Management	**8**	—	—	—	**8**
Operating Margin	**8,999**	—	—	(115)	**8,884**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.
(3) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation, as well as adjustments to reflect the cost of volumes produced on acquired inventory.
(4) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Year Ended December 31, 2024 ($ millions)	Basis of Netback Calculation				
	Foster Creek	Christina Lake	Sunrise	Lloydminster [1]	Total Oil Sands [2]
Gross Sales	5,837	6,428	1,574	3,724	**17,563**
Royalties	(1,176)	(1,601)	(78)	(413)	**(3,268)**
Revenues	4,661	4,827	1,496	3,311	**14,295**
Expenses					
Purchased Product	—	—	—	—	**—**
Transportation and Blending	937	554	294	185	**1,970**
Operating	682	733	263	819	**2,497**
Netback	3,042	3,540	939	2,307	**9,828**
Realized (Gain) Loss on Risk Management					**20**
Operating Margin					**9,808**

Year Ended December 31, 2024 ($ millions)	Basis of Netback Calculation	Adjustments			
	Total Oil Sands [2]	Condensate	Third-party Sourced	Other [3]	Total Oil Sands [4]
Gross Sales	**17,563**	8,913	1,531	440	**28,447**
Royalties	**(3,268)**	—	—	(6)	**(3,274)**
Revenues	**14,295**	8,913	1,531	434	**25,173**
Expenses					
Purchased Product	**—**	—	1,531	320	**1,851**
Transportation and Blending	**1,970**	8,913	—	117	**11,000**
Operating	**2,497**	—	—	14	**2,511**
Netback	**9,828**	—	—	(17)	**9,811**
Realized (Gain) Loss on Risk Management	**20**	—	—	—	**20**
Operating Margin	**9,808**	—	—	(17)	**9,791**

(1) Includes Lloydminster thermal and Lloydminster conventional heavy oil assets.
(2) Includes bitumen and heavy oil.
(3) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation, as well as adjustments to reflect the cost of volumes produced on acquired inventory.
(4) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Conventional

Three Months Ended December 31, 2025 ($ millions)	Basis of Netback Calculation	Adjustments		
	Conventional [1]	Third-party Sourced	Other [1] [2]	Conventional [3]
Gross Sales	**323**	386	29	**738**
Royalties	**(13)**	—	2	**(11)**
Revenues	**310**	386	31	**727**
Expenses				
Purchased Product	**—**	386	—	**386**
Transportation and Blending	**61**	—	31	**92**
Operating	**90**	—	5	**95**
Netback	**159**	—	(5)	**154**
Realized (Gain) Loss on Risk Management	**(5)**	—	—	**(5)**
Operating Margin	**164**	—	(5)	**159**

(1) For the three months ended December 31, 2025, reported netbacks are inclusive of revenues and expenses related to the Duvernay joint venture.
(2) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Three Months Ended December 31, 2024 ($ millions)	Basis of Netback Calculation: Conventional	Adjustments: Third-party Sourced	Adjustments: Other [1]	Conventional [2]
Gross Sales	**273**	470	33	**776**
Royalties	**(15)**	—	—	**(15)**
Revenues	**258**	470	33	**761**
Expenses				
Purchased Product	**—**	470	—	**470**
Transportation and Blending	**52**	—	27	**79**
Operating	**118**	—	5	**123**
Netback	**88**	—	1	**89**
Realized (Gain) Loss on Risk Management	**1**	—	—	**1**
Operating Margin	**87**	—	1	**88**

(1) Other includes reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(2) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Year Ended December 31, 2025 ($ millions)	Basis of Netback Calculation: Conventional [1]	Adjustments: Third-party Sourced	Adjustments: Other [1] [2]	Conventional [3]
Gross Sales	**1,208**	1,337	115	**2,660**
Royalties	**(58)**	—	3	**(55)**
Revenues	**1,150**	1,337	118	**2,605**
Expenses				
Purchased Product	**—**	1,337	—	**1,337**
Transportation and Blending	**244**	—	107	**351**
Operating	**441**	—	23	**464**
Netback	**465**	—	(12)	**453**
Realized (Gain) Loss on Risk Management	**(4)**	—	—	**(4)**
Operating Margin	**469**	—	(12)	**457**

(1) For the year ended December 31, 2025, reported netbacks are inclusive of revenues and expenses related to the Duvernay joint venture.
(2) Other includes the reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(3) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Year Ended December 31, 2024 ($ millions)	Basis of Netback Calculation: Conventional	Adjustments: Third-party Sourced	Adjustments: Other [1]	Conventional [2]
Gross Sales	**1,105**	1,823	131	**3,059**
Royalties	**(76)**	—	—	**(76)**
Revenues	**1,029**	1,823	131	**2,983**
Expenses				
Purchased Product	**—**	1,823	—	**1,823**
Transportation and Blending	**218**	—	102	**320**
Operating	**526**	—	29	**555**
Netback	**285**	—	—	**285**
Realized (Gain) Loss on Risk Management	**(6)**	—	—	**(6)**
Operating Margin	**291**	—	—	**291**

(1) Other includes the reclassification of costs primarily related to third-party cogeneration, processing and transportation.
(2) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Offshore

Three Months Ended December 31, 2025 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	64	275	83	**358**	**422**	(83)	(2)	**337**
Royalties	(1)	(20)	(14)	**(34)**	**(35)**	14	1	**(20)**
Revenues	63	255	69	**324**	**387**	(69)	(1)	**317**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	(6)	**(6)**
Transportation and Blending	3	—	—	**—**	**3**	—	—	**3**
Operating	39	35	22	**57**	**96**	(21)	1	**76**
Netback	21	220	47	**267**	**288**	(48)	4	**244**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**288**	(48)	4	**244**

Three Months Ended December 31, 2024 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	58	315	110	**425**	**483**	(110)	—	**373**
Royalties	—	(25)	(27)	**(52)**	**(52)**	27	—	**(25)**
Revenues	58	290	83	**373**	**431**	(83)	—	**348**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	2	—	—	**—**	**2**	—	—	**2**
Operating	65	35	20	**55**	**120**	(19)	3	**104**
Netback	(9)	255	63	**318**	**309**	(64)	(3)	**242**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**309**	(64)	(3)	**242**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(3) These amounts, excluding Netback, are found in Note 1 of the interim Consolidated Financial Statements.

Year Ended December 31, 2025 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	401	1,088	343	**1,431**	**1,832**	(343)	19	**1,508**
Royalties	(4)	(76)	(83)	**(159)**	**(163)**	83	—	**(80)**
Revenues	397	1,012	260	**1,272**	**1,669**	(260)	19	**1,428**
Expenses								
Purchased Product	—	—	—	**—**	**—**	—	—	**—**
Transportation and Blending	17	—	—	**—**	**17**	—	—	**17**
Operating	223	114	66	**180**	**403**	(58)	4	**349**
Netback	157	898	194	**1,092**	**1,249**	(202)	15	**1,062**
Realized (Gain) Loss on Risk Management					**—**	—	—	**—**
Operating Margin					**1,249**	(202)	15	**1,062**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(3) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Year Ended December 31, 2024 ($ millions)	Basis of Netback Calculation					Adjustments		
	Atlantic	China	Indonesia [1]	Total Asia Pacific	Total Offshore	Equity Adjustment [1]	Other [2]	Total Offshore [3]
Gross Sales	322	1,250	339	**1,589**	**1,911**	(339)	—	**1,572**
Royalties	(2)	(97)	(55)	**(152)**	**(154)**	55	—	**(99)**
Revenues	320	1,153	284	**1,437**	**1,757**	(284)	—	**1,473**
Expenses								
Purchased Product	—	—	—	—	—	—	—	—
Transportation and Blending	11	—	—	—	**11**	—	—	**11**
Operating	287	119	64	**183**	**470**	(56)	9	**423**
Netback	22	1,034	220	**1,254**	**1,276**	(228)	(9)	**1,039**
Realized (Gain) Loss on Risk Management					—	—	—	—
Operating Margin					**1,276**	(228)	(9)	**1,039**

(1) Revenues and expenses related to the HCML joint venture.
(2) Includes other activities not attributable to the production of crude oil and natural gas.
(3) These amounts, excluding Netback, are found in Note 1 of the Consolidated Financial Statements.

Upstream Sales Volumes [1]

The following table provides the sales volumes used to calculate Netback:

(MBOE/d)	Three Months Ended December 31,		Year Ended December 31,	
	2025	2024	**2025**	2024
Oil Sands [2]				
Foster Creek	**227.5**	184.0	**208.0**	188.8
Christina Lake	**315.3**	245.7	**254.8**	231.9
Sunrise	**60.3**	52.2	**53.5**	50.0
Lloydminster	**134.4**	125.9	**126.8**	127.7
Total Oil Sands	**737.5**	607.8	**643.1**	598.4
Conventional [3]	**120.4**	117.8	**122.8**	119.9
Offshore				
Atlantic	**8.0**	6.2	**11.3**	8.0
Asia Pacific				
China	**38.4**	42.6	**38.3**	42.6
Indonesia [4]	**15.6**	19.6	**15.9**	16.0
Total Asia Pacific	**54.0**	62.2	**54.2**	58.6
Total Offshore	**62.0**	68.4	**65.5**	66.6

(1) Sales volumes exclude the impact of purchased condensate.
(2) Includes bitumen and heavy crude oil sales.
(3) For the three months and year ended December 31, 2025, reported sales volumes reflect Cenovus's 30 percent equity interest in the Duvernay joint venture.
(4) Reported sales volumes reflect Cenovus's 40 percent equity interest in the HCML joint venture.

Other Specified Financial Measures

Per-Unit Operating Expenses

Per-unit operating expenses are specified financial measures used to evaluate the performance of our upstream and downstream operations. Our upstream per-unit operating expenses are defined as total operating expenses divided by sales volumes and are part of our Netback calculation, which can be found above.

We define Canadian Refining per-unit operating expenses as total operating expenses from the Upgrader, the Lloydminster Refinery and the commercial fuels business, divided by total processed inputs. We define U.S. Refining per-unit operating expenses as operating expenses divided by total processed inputs.

Per-Unit Transportation Expenses

Per-unit transportation expenses are specified financial measures used to measure transportation expenses on a per-unit basis in our upstream segments. We define per-unit transportation expenses as the total transportation expenses divided by sales volumes. Our upstream per-unit transportation expenses are part of the transportation and blending line in our Netback calculation, which can be found above.

Information for shareholders

Annual Meeting

The meeting will be held virtually. This allows a broader base of shareholders to participate regardless of their location. Holders of Cenovus common shares are invited to attend the virtual Annual Meeting of Shareholders on Wednesday, May 6, 2026 at 11:00 am. MT via live webcast accessible online at **https://meetings.lumiconnect.com/400-630-265-895**
Password: cenovus2026

Please see our Management Information Circular available on **cenovus.com** for additional information.

Registrar and transfer agent

Computershare Investor Services Inc.
320 Bay Street, 14th Floor
Toronto, ON M5H 4A6
https://www.cenovus.com/Investors/Shareholder-information
Shareholder inquiries by phone:
North America 1-866-332-8898 (English and French)
Outside North America 1-514-982-8717 (English and French)

Shareholder account matters

For information regarding your shareholdings or to change your address, transfer shares, eliminate duplicate mailings, directly deposit dividends, etc., please contact Computershare Investor Services Inc. If your shares are held by a broker, please contact your broker.

Stock exchanges

Cenovus common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol CVE.

Annual Information Form/Form 40-F

Our Annual Information Form is filed with the Canadian Securities Administrators in Canada on SEDAR+ at **sedarplus.ca** and with the U.S. Securities and Exchange Commission under the Multi-Jurisdictional Disclosure System as an Annual Report on Form 40-F on EDGAR at **sec.gov**.

NYSE corporate governance standards

As a Canadian company listed on the NYSE, we are not required to comply with most of the NYSE corporate governance standards and instead may comply with Canadian corporate governance requirements. We are, however, required to disclose the significant differences between our corporate governance practices and those required to be followed by U.S. domestic companies under the NYSE corporate governance standards. Except as summarized on **https://www.cenovus.com/Our-company/Governance**, we are in compliance with the NYSE corporate governance standards in all significant respects.

Investor Relations

Please visit the Investors section at **cenovus.com** for investor information.

Investor inquiries should be directed to:
403-766-7711, **investor.relations@cenovus.com**

Media inquiries should be directed to:
403-766-7751, **media.relations@cenovus.com**

Cenovus head office

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Cenovus's Leadership Team

(as at March 10, 2026)

Jon McKenzie, President & Chief Executive Officer
Susan Anderson, SVP, Legal, General Counsel & Corporate Secretary
Andrew Dahlin, EVP & Chief Operating Officer
Jeff Lawson, EVP, Corporate Development & Chief Sustainability Officer
Geoff Murray, EVP, Commercial
Candace Newman, SVP, People Services
Kam Sandhar, EVP & Chief Financial Officer
John Soini, EVP, Upstream – Thermal & Atlantic Offshore
Eric Zimpfer, Head of Downstream

Cenovus's Board of Directors

(as at March 10, 2026)

Alex Pourbaix, Chair, Calgary, Alberta [5]
Claude Mongeau, Lead Independent Director, Montréal, Québec [1,2]
Stephen E. Bradley, Smerillo, Italy [1,4]
Keith M. Casey, San Antonio, Texas [3,4]
Michael J. Crothers, Calgary, Alberta [2,3]
James D. Girgulis, Luxembourg, Grand-Duchy of Luxembourg [3,4]
Jane E. Kinney, Toronto, Ontario [1,4]
Eva L. Kwok, Vancouver, British Columbia [2]
Melanie A. Little, Alpharetta, Georgia [3,4]
Richard J. Marcogliese, Alamo, California [1,4]
Chana L. Martineau, Edmonton, Alberta [1,2]
Jon McKenzie, Calgary, Alberta [6]
Frank J. Sixt, Hong Kong Special Administrative Region [2]
Rhonda I. Zygocki, Friday Harbor, Washington [2,3]

(1) Member of the Audit Committee.
(2) Member of the Governance Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Safety, Sustainability and Reserves Committee.
(5) As a non-independent director, Mr. Pourbaix is not a member of any of the committees of Cenovus's Board.
(6) As an officer and non-independent director, Mr. McKenzie is not a member of any of the committees of Cenovus's Board.

CENOVUS ENERGY INC.

Cenovus Energy Inc. is an integrated energy company with oil and natural gas production operations in Canada and the Asia Pacific region, and upgrading, refining and marketing operations in Canada and the United States. The company is committed to maximizing value by developing its assets in a safe, responsible and cost-efficient manner, integrating sustainability considerations into its business plans. Cenovus common shares are listed on the Toronto and New York stock exchanges.

For more information, visit **cenovus.com**.

cenovus ENERGY

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