BAYTEX

Focused **Discipline.**

Enhanced **Value.**

2025

ANNUAL REPORT

NYSE | TSX BTE

2025 Highlights

$3.0 billion
Strategic divestiture of U.S. assets

Repositioned
portfolio into a **focused Canadian oil producer**

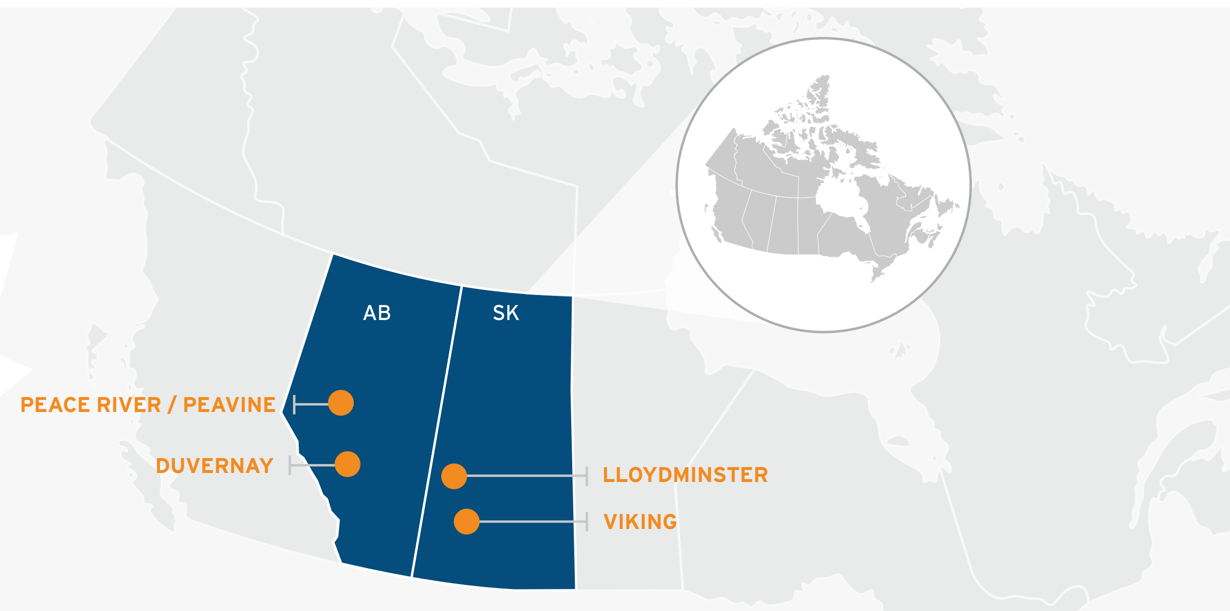
6% Canadian
production growth
(excl. divestitures)

$857 million
Significantly strengthened financial position with cash on balance sheet

Accelerated shareholder returns
Re-initiated share buybacks on December 24

$69 million
Returned to shareholders through quarterly dividend

Our **Operating Areas**



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NYSE | TSX BTE

2025 Summary

		Twelve Months Ended	
FINANCIAL		December 31, 2025	December 31, 2024
(thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$**	**3,573,172**	$ 4,208,955
Adjusted funds flow (1)		**1,514,552**	1,956,518
Per share - basic		**1.97**	2.44
Per share - diluted		**1.97**	2.42
Free cash flow (2)		**274,891**	655,582
Per share - basic		**0.36**	0.82
Per share - diluted		**0.36**	0.81
Cash flows from operating activities		**1,485,962**	1,908,264
Per share - basic		**1.93**	2.38
Per share - diluted		**1.93**	2.36
Net (loss) income		**(603,779)**	236,597
Per share - basic		**(0.78)**	0.29
Per share - diluted		**(0.78)**	0.29
Dividends declared		**69,187**	71,985
Per share		**0.090**	0.090
Capital Expenditures			
Exploration and development expenditures	**$**	**1,206,071**	$ 1,256,633
Acquisitions and (divestitures)		**(2,991,285)**	5,920
Total oil and natural gas capital expenditures	**$**	**(1,785,214)**	$ 1,262,553
Net (Cash) Debt			
Credit facilities	**$**	**1,400**	$ 341,207
Long-term notes		**95,947**	1,980,619
Total debt (3)		**97,347**	2,321,826
Working capital (surplus) deficiency (2)		**(863,132)**	95,346
Net (cash) debt (1)	**$**	**(765,785)**	$ 2,417,172
Shares Outstanding - basic (thousands)			
Weighted average		**769,180**	803,435
End of period		**765,568**	773,590
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$**	**64.81**	$ 75.72
MEH oil (US$/bbl)		**66.66**	77.99
MEH oil differential to WTI (US$/bbl)		**1.85**	2.27
Edmonton par ($/bbl)		**85.53**	97.59
Edmonton par differential to WTI (US$/bbl)		**(3.62)**	(4.49)
WCS heavy oil ($/bbl)		**75.06**	83.56
WCS differential to WTI (US$/bbl)		**(11.11)**	(14.73)
Natural gas			
NYMEX (US$/mmbtu)	**$**	**3.43**	$ 2.27
AECO ($/mcf)		**1.86**	1.44
CAD/USD average exchange rate		**1.3978**	1.3700

(1) Capital management measure. Refer to the Specified Financial Measures section in the press release dated March 4, 2026 for further information.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in the press release dated March 4, 2026 for further information.

(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at *www.sedarplus.ca*.

2025 Summary

		Twelve Months Ended		
OPERATING		December 31, 2025		December 31, 2024
Daily Production				
Light oil and condensate (bbl/d)		**11,897**		11,983
Heavy oil (bbl/d)		**42,775**		42,313
NGL (bbl/d)		**3,524**		2,749
Total liquids (bbl/d)		**58,196**		57,045
Natural gas (mcf/d)		**43,988**		41,412
Total Canada (boe/d) (1)		**65,528**		63,948
Discontinued operations (boe/d) (1)		**79,551**		89,100
Oil equivalent (boe/d) (1)		**145,079**		153,048
Adjusted Funds Flow (thousands of Canadian dollars)				
Total sales, net of blending and other expense (2)	**$**	**1,449,658**	$	1,610,103
Royalties		**(203,833)**		(261,205)
Operating expense		**(334,317)**		(336,069)
Transportation expense		**(83,697)**		(84,211)
Operating netback - Canada (2)	**$**	**827,811**	$	928,618
General and administrative		**(67,903)**		(58,363)
Cash interest		**(161,432)**		(188,632)
Realized financial derivatives (loss) gain		**(19,635)**		1,447
Other (3)		**(36,251)**		(26,516)
Adjusted funds flow - Canada (4)	**$**	**542,590**	$	656,554
Adjusted funds flow - Discontinued operations (4)	**$**	**971,962**	$	1,299,964
Adjusted funds flow (4)	**$**	**1,514,552**	$	1,956,518
Adjusted Funds Flow (per boe)				
Total sales, net of blending and other expense (2)	**$**	**60.61**	$	68.79
Royalties (5)		**(8.52)**		(11.16)
Operating expense (5)		**(13.98)**		(14.36)
Transportation expense (5)		**(3.50)**		(3.60)
Operating netback - Canada (2)	**$**	**34.61**	$	39.67
General and administrative (5)		**(2.84)**		(2.49)
Cash interest (5)		**(6.75)**		(8.06)
Realized financial derivatives (loss) gain (5)		**(0.82)**		0.06
Other (3)		**(1.52)**		(1.13)
Adjusted funds flow - Canada (4)	**$**	**22.68**	$	28.05
Adjusted funds flow - Discontinued operations (4)	**$**	**33.47**	$	39.86
Adjusted funds flow (4)	**$**	**28.60**	$	34.93

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in the press release dated March 4, 2026 for further information.

(3) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the 2025 MD&A for further information on these amounts.

(4) Capital management measure. Refer to the Specified Financial Measures section in the press release dated March 4, 2026 for further information.

(5) Calculated as royalties, operating expense, transportation expense, general and administrative expense, cash interest expense or realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period for Canada.

BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2025 RESULTS AND CEO SUCCESSION; COMPLETES TRANSITION TO A FOCUSED CANADIAN ENERGY COMPANY

CALGARY, ALBERTA (March 4, 2026) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2025 (all amounts are in Canadian dollars unless otherwise noted).

"2025 was a definitive year for Baytex, marked by the successful repositioning of our portfolio into a focused, high-return Canadian oil producer," said Eric T. Greager, Chief Executive Officer. "We strengthened our financial position and reinforced our potential for long-term value creation. With a sustaining breakeven of US$52/bbl WTI, Baytex is well-positioned to navigate market volatility and accelerate shareholder returns. Our 2026 plan is already delivering operational momentum across our core Pembina Duvernay and heavy oil fairways, and I am confident the company is set up for a seamless leadership transition."

2025 Highlights

- Completed the divestiture of U.S. Eagle Ford assets for net proceeds of $3.0 billion on December 19, 2025, successfully transitioning Baytex to a focused Canadian producer.
- Significantly strengthened financial position with cash of $857 million (cash less principal amount of Senior Notes that remain outstanding).
- Delivered 2025 Canadian production of 65,528 boe/d (89% oil and NGL), representing 6% organic growth over 2024. Q4/2025 Canadian production averaged 67,295 boe/d (88% oil and NGL).
- Reported a 2025 net loss of $604 million ($0.78 per basic share) due to non-cash, one-time items associated with the Eagle Ford divestiture and a Viking impairment, with no impact to cash flow.
- Reported cash flows from operating activities of $1.5 billion ($1.93 per basic share) for 2025, including $228 million ($0.30 per basic share) in the fourth quarter.
- Delivered full-year adjusted funds flow(1) of $1.5 billion ($1.97 per basic share) with $262 million ($0.34 per basic share) generated in Q4/2025.
- Realized free cash flow(2) of $275 million ($0.36 per basic share) for the full-year, including $76 million ($0.10 per basic share) in Q4/2025.
- Re-initiated share buybacks on December 24, 2025. To-date, Baytex has repurchased 30 million shares (3.9% of shares outstanding) for $141 million.
- Declared total cash dividends of $0.09 per share in 2025, representing $69 million returned to shareholders.

CEO Succession

Chad Lundberg, President and Chief Operating Officer, will succeed Eric Greager as Chief Executive Officer following the Annual General Meeting ("AGM") on May 7, 2026. Mr. Lundberg joined Baytex in 2018 and has played an instrumental role in the strategic development and operational expansion of the Company's portfolio. To ensure a seamless transition, Mr. Greager will remain as CEO and a member of the Board until the AGM, at which time Mr. Lundberg will be nominated for election as a Director.

"The Board has been committed to a rigorous succession process to ensure Baytex is led by the right individual for our next chapter," said Mark Bly, Chair of the Board of Directors. "As we sharpen our focus on our core Canadian assets, Chad's deep operational expertise and proven leadership make him the right choice to drive our business forward. We are confident that his strategic vision and commitment to financial discipline will drive continued value creation. On behalf of the Board, I thank Eric for positioning the company for success and establishing the strong foundation from which Chad will now lead."

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standard ("IFRS") and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.

2026 Outlook: Focused Canadian Operations

Baytex enters 2026 as a focused Canadian producer with a high-quality asset base centered on heavy oil operations and an attractive position in the Pembina Duvernay.

Our 2026 budget, released in December 2025, targets annual production of 67,000 to 69,000 boe/d, representing 3% to 5% organic growth year-over-year, with E&D expenditures of $550 to $625 million. This plan is designed to deliver disciplined growth while investing in the long-term infrastructure and exploration to support future value creation. We have significant inventory depth and optionality across our portfolio to support our current plan and potentially accelerate growth beyond these levels.

We are efficiently executing our first quarter capital program with seven rigs currently active across our portfolio. Production in Q1/2026 is forecast to average 68,000 to 69,000 boe/d, with production increasing to approximately 70,000 boe/d as we exit 2026.

Our heavy oil assets comprise 750,000 net acres and 1,100 drilling locations, supporting approximately 12 years of drilling at our current pace of development. We currently have five drilling rigs active across our heavy oil fairway targeting the Clearwater at Peavine and the broader Mannville stack in Lloydminster. We expect to bring 91 heavy oil wells onstream in 2026.

Our 2026 program will see increased exploration activity, including stratigraphic tests, step-out wells and 3-D seismic, to expand our development inventory and test new play concepts across our extensive heavy oil fairway. In addition, we are advancing two waterflood pilot projects at Peavine, blending the attractive capital efficiencies of multi-lateral primary development with the potential for enhanced recovery and moderated decline rates.

In the Duvernay, we have assembled 91,500 net acres and identified approximately 210 drilling locations. Production is expected to increase 35% to average approximately 11,000 boe/d in 2026, with a target year-end exit rate of 14,000 to 15,000 boe/d. We currently have one rig drilling a four-well pad on our southern acreage. Completion operations are scheduled for the second quarter with the wells expected to be onstream by mid-year. The remaining two pads are expected onstream during the third and fourth quarters.

2025 Results

On December 19, 2025, Baytex completed the divestiture of its U.S. Eagle Ford assets for net proceeds of US$2.2 billion ($3.0 billion in Canadian dollars) after closing adjustments. As a result of the disposition, results from the operated and non-operated Eagle Ford properties have been classified as discontinued operations for the current and comparative periods.

For the full-year 2025, adjusted funds flow(1) totaled $1.5 billion ($1.97 per basic share) and we generated free cash flow(2) of $275 million ($0.36 per basic share). In the fourth quarter, we incurred non-recurring, one-time cash tax and severance costs associated with the Eagle Ford divestiture. These expensed items reduced adjusted funds flow by $37 million ($0.05 per basic share). In addition, we reported a net loss of $604 million ($0.78 per basic share), primarily driven by non-cash, one-time items associated with the strategic repositioning of the portfolio. These include a loss on the Eagle Ford disposition, a deferred tax adjustment related to the transaction structure, and an impairment on Viking assets.

Canadian production averaged 65,528 boe/d (89% oil and NGL) in 2025, representing 6% organic growth over 2024 (excluding non-core divestitures). Fourth quarter Canadian production averaged 67,295 boe/d (88% oil and NGL). Exploration and development expenditures in Canada totaled $548 million for the full-year, including $93 million in the fourth quarter, reflecting a highly capital-efficient program.

Accelerated Shareholder Returns

Baytex entered 2026 with a cash position of $857 million (cash less principal amount of Senior Notes that remain outstanding), providing significant financial flexibility to support our commitment to shareholder returns. We intend to prioritize share buybacks while maintaining our current annual dividend of $0.09 per share.

Following the close of the Eagle Ford sale, we re-initiated our share buyback program on December 24, 2025. To date (through March 3, 2026), we have repurchased 30 million shares for $141 million, representing 3.9% of our shares outstanding at an average price of $4.72 per share. Our current Normal Course Issuer Bid ("NCIB") allows for the purchase of up to 66.2 million shares through the 12-month period ending July 1, 2026.

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Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2026 for shareholders of record on March 13, 2026.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2025 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", ""estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: that we have a sustaining breakeven of US$52/bbl WTI, are well positioned to navigate market volatility and accelerate shareholder returns and set up for a seamless leadership transition; that Chad Lundberg will succeed Eric Greager as chief executive officer on May 7, 2026; our development plans for 2026, our expected full-year production volumes, expected production growth rate and exploration and development expenditures; that we can accelerate growth beyond these levels; our expected Q1/2026 production rate and 2026 exit production rate; in our heavy oil assets: that we have 12 years of drilling locations at our current pace of development, expect to bring 91 wells on stream in 2026 and types of activity we will carry out; in the Duvernay: our expected average annual and target year-end exit target production rate for 2026, and the timing for completion activities and wells onstream; that we intend to prioritize share buybacks while maintaining our dividend. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; that we will have sufficient financial resources in the future to provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices (including as a result of tariffs); risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants *in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Corporation and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.*

The future acquisition of our common shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) or acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2025, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on March 4, 2026 and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2026 guidance for development expenditures; and our intentions of allocating funds to share buybacks and a dividend; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, working capital (surplus) deficiency and total sales, net of blending and other expense) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This press release also contains the terms "adjusted funds flow" and "net (cash) debt" which are considered capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback is used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense.

The following table reconciles operating netback to petroleum and natural gas sales for Canada.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Petroleum and natural gas sales	**$ 381,556**	$ 437,905	$ 466,706	**$ 1,684,648**	$ 1,874,046
Blending and other expense	**(50,039)**	(49,750)	(80,148)	**(234,990)**	(263,943)
Total sales, net of blending and other expense	**$ 331,517**	$ 388,155	$ 386,558	**$ 1,449,658**	$ 1,610,103
Royalties	**(43,132)**	(53,645)	(60,396)	**(203,833)**	(261,205)
Operating expense	**(85,708)**	(84,994)	(78,878)	**(334,317)**	(336,069)
Transportation expense	**(21,314)**	(23,060)	(21,595)	**(83,697)**	(84,211)
Operating netback - Canada	**$ 181,363**	$ 226,456	$ 225,689	**$ 827,811**	$ 928,618

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, transaction costs, additions to exploration and evaluation assets, additions to oil and gas properties, and payments on lease obligations.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Cash flows from operating activities	**$ 227,657**	$ 472,676	$ 468,865	**$ 1,485,962**	$ 1,908,264
Change in non-cash working capital	**(226)**	(55,961)	(13,428)	**(18,111)**	17,922
Transaction costs	**26,383**	—	—	**26,383**	1,539
Additions to exploration and evaluation assets	**—**	—	—	**(930)**	—
Additions to oil and gas properties	**(174,078)**	(270,364)	(198,177)	**(1,205,141)**	(1,256,633)
Payments on lease obligations	**(3,250)**	(3,663)	(2,422)	**(13,272)**	(15,510)
Free cash flow	**$ 76,486**	$ 142,688	$ 254,838	**$ 274,891**	$ 655,582

Working capital (surplus) deficiency

Working capital (surplus) deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, share-based compensation liability, other long-term liabilities, and dividends payable. Working capital (surplus) deficiency is used by management to measure the Company's liquidity. At December 31, 2025, the Company had $744.2 million of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital (surplus) deficiency.

	As at		
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024
Cash	**$ (953,113)**	$ (10,417)	$ (16,610)
Trade receivables	**(135,230)**	(324,287)	(387,266)
Prepaids and other assets	**(63,232)**	(75,100)	(76,468)
Trade payables	**236,373**	554,057	512,473
Share-based compensation liability	**34,802**	24,666	24,732
Other long-term liabilities	**—**	20,163	20,887
Dividends payable	**17,268**	17,326	17,598
Working capital (surplus) deficiency	**$ (863,132)**	$ 206,408	$ 95,346

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Operating netback per boe

Operating netback per boe is equal to operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net (cash) debt

We use net (cash) debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net (cash) debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net (cash) debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash, trade receivables, and prepaids and other assets.

The following table summarizes our calculation of net (cash) debt.

	As at		
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024
Credit facilities	**$ 1,138**	$ 166,841	$ 324,346
Unamortized debt issuance costs - Credit facilities (1)	**262**	15,504	16,861
Long-term notes	**93,834**	1,815,230	1,932,890
Unamortized debt issuance costs - Long-term notes (1)	**2,113**	40,375	47,729
Trade payables	**236,373**	554,057	512,473
Share-based compensation liability	**34,802**	24,666	24,732
Dividends payable	**17,268**	17,326	17,598
Other long-term liabilities	**—**	20,163	20,887
Cash	**(953,113)**	(10,417)	(16,610)
Trade receivables	**(135,230)**	(324,287)	(387,266)
Prepaids and other assets	**(63,232)**	(75,100)	(76,468)
Net (cash) debt	**$ (765,785)**	$ 2,244,358	$ 2,417,172

(1) *Unamortized debt issuance costs were obtained from Note 9 Credit Facilities and Note 10 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2025.*

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirement obligations settled, and transaction costs during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Cash flows from operating activities	**$ 227,657**	$ 472,676	$ 468,865	**$ 1,485,962**	$ 1,908,264
Change in non-cash working capital	**(226)**	(55,961)	(13,428)	**(18,111)**	17,922
Asset retirement obligations settled	**7,717**	5,517	6,449	**20,318**	28,793
Transaction costs	**26,383**	—	—	**26,383**	1,539
Adjusted funds flow	**$ 261,531**	$ 422,232	$ 461,886	**$ 1,514,552**	$ 1,956,518

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Duvernay, Baytex's net drilling locations include 58 proved and 11 probable locations as at December 31, 2025 and 141 unbooked locations. In the Viking, Baytex's net drilling locations include 457 proved and 196 probable locations as at December 31, 2025 and 263 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 160 proved and 167 probable locations as at December 31, 2025 and 773 unbooked locations.

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2025. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2025					Twelve Months Ended December 31, 2025				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,493	8	35	8,974	11,032	9,726	12	32	9,629	11,374
Lloydminster	13,702	16	1	1,465	13,963	12,700	19	—	1,258	12,928
Peavine	18,582	—	—	—	18,582	19,235	—	—	—	19,235
Remaining Properties	802	3	—	660	915	1,034	2	—	680	1,150
Canada - Light										
Viking	40	7,213	259	9,388	9,076	74	7,813	205	10,071	9,771
Duvernay	—	4,585	3,594	14,801	10,645	—	3,757	2,767	10,825	8,328
Remaining Properties	9	206	599	13,607	3,082	6	294	520	11,525	2,742
Total Canada	42,628	12,031	4,488	48,895	67,295	42,775	11,897	3,524	43,988	65,528
United States										
Eagle Ford	—	42,109	13,524	84,950	69,792	—	48,971	15,491	90,528	79,551
Total	42,628	54,140	18,012	133,845	137,087	42,775	60,868	19,015	134,516	145,079

Baytex Energy Corp.

Baytex Energy Corp. is a Calgary-based energy company committed to driving shareholder value through disciplined execution. It operates a high-quality, high-return portfolio in the Western Canadian Sedimentary Basin, featuring the Pembina Duvernay and heavy oil plays in Alberta and Saskatchewan. These core assets are backed by an extensive drilling inventory and consistently generate strong cash flow. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

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Management's Discussion and Analysis
For the years ended December 31, 2025 and 2024
Dated March 4, 2026

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2025 and 2024. This information is provided as of March 4, 2026. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months and year ended December 31, 2025 ("Q4/2025" and "2025") have been compared with the results for the three months and year ended December 31, 2024 ("Q4/2024" and "2024"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2025 and 2024, together with the accompanying notes and the Annual Information Form ("AIF") for the year ended December 31, 2025. These documents and additional information about Baytex are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted. Operating and financial results for our continuing operations are presented separately from the operating and financial results of discontinued operations. Presentation of comparative period results has been revised to reflect current period presentation.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow" and "net (cash) debt" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a Canadian energy company based in Calgary, Alberta. Following the disposition of our U.S. operations in Q4/2025, Baytex has oil and natural gas assets in Western Canada primarily comprised of Viking and Duvernay light oil assets along with heavy oil assets in Peace River and Lloydminster.

PRESENTATION OF CONTINUING AND DISCONTINUED OPERATIONS

On December 19, 2025, we completed the disposition of the operated and non-operated Eagle Ford assets which comprised our U.S. operating segment. This operating segment represented a geographical area of our operations and its results have been classified as discontinued operations. The financial results for the year ended December 31, 2025 and December 31, 2024 are disaggregated between continuing and discontinued operations in the table below.

In this MD&A, references to "Canada", "Canadian operations" and similar terms refer to the continuing operations of Baytex Energy Corp. and references to "U.S. operations", "Eagle Ford" and similar terms refer to the discontinued operations.

	2025			2024		
Years Ended December 31	**Continuing**	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 1,684,648**	**$ 1,888,524**	**$ 3,573,172**	$ 1,874,046	$ 2,334,909	$ 4,208,955
Royalties	**(203,833)**	**(508,305)**	**(712,138)**	(261,205)	(618,881)	(880,086)
	1,480,815	**1,380,219**	**2,861,034**	1,612,841	1,716,028	3,328,869
Expenses						
Operating	**334,317**	**292,424**	**626,741**	336,069	317,880	653,949
Transportation	**83,697**	**45,683**	**129,380**	84,211	48,931	133,142
Blending and other	**234,990**	**—**	**234,990**	263,943	—	263,943
General and administrative	**67,903**	**35,622**	**103,525**	58,363	23,383	81,746
Transaction costs	**—**	**—**	**—**	1,539	—	1,539
Exploration and evaluation	**5,534**	**—**	**5,534**	779	—	779
Depletion and depreciation	**484,932**	**779,760**	**1,264,692**	483,314	902,596	1,385,910
Impairment	**148,000**	**—**	**148,000**	—	—	—
Share-based compensation	**24,041**	**9,268**	**33,309**	11,871	6,001	17,872
Financing and interest	**322,017**	**22,985**	**345,002**	244,951	23,423	268,374
Financial derivatives loss (gain)	**17,071**	**—**	**17,071**	(2,101)	—	(2,101)
Foreign exchange (gain) loss	**(94,019)**	**(3,624)**	**(97,643)**	155,895	—	155,895
(Gain) loss on dispositions	**(2,528)**	**510,608**	**508,080**	(4,134)	5,354	1,220
Other expense (income)	**7,970**	**(4,061)**	**3,909**	(5,141)	(1,548)	(6,689)
	1,633,925	**1,688,665**	**3,322,590**	1,629,559	1,326,020	2,955,579
Net (loss) income before income taxes	**(153,110)**	**(308,446)**	**(461,556)**	(16,718)	390,008	373,290
Income taxes						
Current income tax expense	**9,721**	**20,261**	**29,982**	17,821	3,945	21,766
Deferred income tax expense (recovery)	**114,014**	**(1,773)**	**112,241**	62,914	52,013	114,927
	123,735	**18,488**	**142,223**	80,735	55,958	136,693
Net (loss) income	**$ (276,845)**	**$ (326,934)**	**$ (603,779)**	$ (97,453)	$ 334,050	$ 236,597

2025 ANNUAL HIGHLIGHTS

Baytex delivered strong operating results in 2025. Annual production of 145,079 boe/d was consistent with our full year plan after adjusting for the disposition of the Eagle Ford assets on December 19, 2025, and reflects strong results from our drilling programs in Western Canada and the Eagle Ford in Texas. We invested $1.2 billion in exploration and development expenditures and generated free cash flow[(1)] of $274.9 million in 2025.

Exploration and development expenditures totaled $1.2 billion for 2025. In Canada, we invested $548.4 million and generated production of 65,528 boe/d during 2025 compared to 63,948 boe/d in 2024 which reflects strong well performance from our light oil Duvernay assets and heavy oil development which more than offset the effect of the disposition of our Kerrobert thermal asset in Q4/2024. In the U.S. we invested $657.7 million during 2025 and production averaged 79,551 boe/d compared to 89,100 boe/d in 2024 when we invested $767.1 million.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Oil prices were volatile in 2025 due to concerns over global economic conditions along with increasing supply. The average WTI benchmark price for 2025 was US$64.81/bbl which was US$10.91/bbl lower than an average of US$75.72/bbl for 2024. Our financial results for 2025 reflect lower realized pricing which resulted in adjusted funds flow(1) of $1.5 billion and cash flows from operating activities of $1.5 billion for 2025 compared to 2024 when we generated adjusted funds flow of $2.0 billion and cash flows from operating activities of $1.9 billion.

Baytex completed the disposition of the operated and non-operated Eagle Ford assets on December 19, 2025. Proceeds of approximately US$2.2 billion (after closing adjustments) were used to repay a significant portion of our outstanding debt and to restart our share buyback program. The divestiture positions Baytex as a focused Canadian energy producer with high-quality heavy oil operations as well as an attractive position in the Pembina Duvernay.

Net cash(1) was $765.8 million at December 31, 2025 compared to net debt(1) of $2.4 billion at December 31, 2024. Our net cash(1) position at December 31, 2025 reflects proceeds received from the disposition of the Eagle Ford assets which were used for the repayment of our credit facilities, all of the 8.50% Senior Notes due 2030 and the majority of the 7.375% Senior Notes due 2032. Free cash flow of $274.9 million generated throughout 2025 was allocated to debt repayment along with $98.0 million of shareholder returns including share buybacks and quarterly dividends.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

GUIDANCE

Our 2026 annual guidance reflects our plans for the continuing Canadian operations, which includes exploration and development expenditures of $550 - $625 million and is designed to generate annual production of 67,000 - 69,000 boe/d.

The following table compares our 2025 revised annual guidance and 2026 annual guidance to our 2025 results. Production, exploration and development expenditures, and expenses for 2025 were consistent with our revised annual guidance for 2025, which reflects our ongoing efforts to deliver strong operating results while we maintain a competitive cost structure.

	2025 Annual Guidance	2025 Results (1)	2026 Annual Guidance (2)
Exploration and development expenditures (3)	~ $1.2 billion	$1.21 billion	$550 - $625 million
Production (boe/d) (3)	~ 148,000	145,079	67,000 - 69,000
Expenses:			
Average royalty rate (3)(4)	~ 22%	21.3%	15%
Operating (5)(6)	$11.75 - $12.00/boe	$11.84/boe	$13.75 - $14.25/boe
Transportation (6)(7)	$2.40 - $2.55/boe	$2.44/boe	$3.40 - $3.60/boe
General and administrative (3)(6)	$95 million ($1.76/boe)	$103.5 million ($1.96/boe)	
Cash Interest (6)(7)	$180 million ($3.33/boe)	$174.1 million ($3.29/boe)	
Current Income Taxes (5)	< 1% of EBITDA (8)	1.7% of EBITDA (8)	
Leasing expenditures	$15 million	$13 million	$7 million
Asset retirement obligations settled	$20 million	$20 million	$20 million

(1) Includes both continuing and discontinued operations up to closing of the Eagle Ford disposition on December 19, 2025.
(2) As announced on December 22, 2025.
(3) As announced on July 31, 2025.
(4) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(5) As announced on October 30, 2025.
(6) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.
(7) As announced on December 3, 2024.
(8) EBITDA is calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2025	2024	Change
Daily Production			
Liquids (bbl/d)			
Light oil and condensate	**11,897**	11,983	(1)%
Heavy oil	**42,775**	42,313	1 %
Natural Gas Liquids ("NGL")	**3,524**	2,749	28 %
Total liquids (bbl/d)	**58,196**	57,045	2 %
Natural gas (mcf/d)	**43,988**	41,412	6 %
Daily production (boe/d) - continuing operations	**65,528**	63,948	2 %
Daily production (boe/d) - discontinued operations	**79,551**	89,100	(11)%
Total production (boe/d)	**145,079**	153,048	(5)%
Production Mix - continuing operations			
Light oil and condensate	**19%**	19%	—%
Heavy oil	**65%**	66%	(1%)
NGL	**5%**	4%	1%
Natural gas	**11%**	11%	—%

Production from continuing operations in Canada increased to 65,528 boe/d in 2025 compared to 63,948 boe/d in 2024. Our successful light and heavy oil development programs resulted in production that was 1,580 boe/d higher than 2024 despite the disposition of 2,000 boe/d of heavy oil production from the Kerrobert thermal assets in Q4/2024.

Production from discontinued operations of 79,551 boe/d for 2025 was lower than 89,100 boe/d for 2024 which reflects lower activity on the non-operated Eagle Ford assets prior to disposition of all of the Eagle Ford assets on December 19, 2025.

Total production of 145,079 boe/d was consistent with our revised annual guidance of approximately 148,000 boe/d after adjusting for the Eagle Ford disposition on December 19, 2025. We expect production in 2026 to average 67,000 - 69,000 boe/d which reflects growth from our light and heavy oil development activity in Canada.

COMMODITY PRICES

The prices received for our crude oil and natural gas production directly impact our earnings, free cash flow and our financial position.

Crude Oil

Global benchmark prices for crude oil declined in 2025 compared to 2024 as a result of increasing supply and concerns over slowing global economic activity. The WTI benchmark price averaged US$64.81/bbl for 2025 compared to US$75.72/bbl for 2024. Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets and the cost of transportation from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada. Canadian oil differentials were narrower in 2025 compared to 2024 after exports commenced from the TMX pipeline expansion in May 2024.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $85.53/bbl for 2025 compared to $97.59/bbl for 2024. Edmonton par traded at a US$3.62/bbl discount to WTI in 2025 compared to a discount of US$4.49/bbl for 2024.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark price for 2025 averaged $75.06/bbl compared to $83.56/bbl for 2024. The WCS heavy oil differential to WTI was US$11.11/bbl in 2025 compared to US$14.73/bbl in 2024 due to the additional egress capacity from the Trans Mountain pipeline expansion.

Natural Gas

Natural gas prices in Canada were higher in 2025 compared to 2024 which reflects incremental demand and lower inventory levels. Our natural gas pricing is based on the AECO benchmark which trades at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $1.86/mcf during 2025 which is higher than $1.44/mcf during 2024.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
	2025	2024	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**64.81**	75.72	(10.91)
Edmonton par oil ($/bbl) [(2)]	**85.53**	97.59	(12.06)
Edmonton par oil differential to WTI (US$/bbl)	**(3.62)**	(4.49)	0.87
WCS heavy oil ($/bbl) [(3)]	**75.06**	83.56	(8.50)
WCS heavy oil differential to WTI (US$/bbl)	**(11.11)**	(14.73)	3.62
AECO 7A natural gas price ($/mcf) [(4)]	**1.86**	1.44	0.42
AECO 5A natural gas price ($/mcf) [(5)]	**1.68**	1.45	0.23
CAD/USD average exchange rate	**1.3978**	1.3700	0.0278

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(3) WCS refers to the average posting price for the benchmark WCS heavy oil.
(4) AECO 7A refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) AECO 5A refers to the AECO arithmetic average daily index price published by the Canadian Gas Price Reporter ("CGPR").

	Years Ended December 31		
	2025	2024	Change
Average Realized Sales Prices			
Light oil and condensate ($/bbl) [(1)]	**$ 84.41**	$ 96.08	$ (11.67)
Heavy oil, net of blending and other expense ($/bbl) [(2)]	**65.77**	73.55	(7.78)
NGL ($/bbl) [(1)]	**23.00**	25.85	(2.85)
Natural gas ($/mcf) [(1)]	**1.66**	1.56	0.10
Total sales, net of blending and other expense ($/boe) [(2)] - continuing operations	**$ 60.61**	$ 68.79	$ (8.18)
Total sales ($/boe) [(2)] - discontinued operations	**$ 65.04**	$ 71.60	$ (6.56)
Total sales, net of blending and other expense ($/boe) [(2)]	**$ 63.04**	$ 70.43	$ (7.39)

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe was $60.61/boe for 2025 for our continuing Canadian operations compared to $68.79/boe for 2024. The decrease in realized pricing was primarily due to lower benchmark oil pricing in 2025 relative to 2024.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Lower benchmark prices resulted in our realized light oil and condensate price of $84.41/bbl for 2025 compared to $96.08/bbl in 2024. Our realized price represents a discount of $1.12/bbl to the Edmonton par benchmark compared to $1.51/bbl in 2024 which reflects production growth from our Duvernay light oil assets in 2025.

Our Canadian realized heavy oil price, net of blending and other expense[1] was lower in 2025 compared to 2024 which reflects the decrease in WCS benchmark pricing. Our realized pricing for 2025 represents a discount to the WCS benchmark of $9.29/bbl compared to $10.01/bbl for 2024 which reflects lower blending costs in 2025.

In Canada, our realized NGL price as a percentage of WTI varies based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Expressed in Canadian dollars, our realized NGL price[2] was 25% of WTI in 2025 and 2024.

We compare our Canadian realized natural gas price to the AECO benchmark price. A portion of our natural gas sales is based on the daily index prices which fluctuate independently from the associated monthly index prices. Our realized natural gas price of $1.66/mcf for 2025 reflects higher benchmark prices compared to 2024 when our realized price was $1.56/mcf.

Our total sales for discontinued operations was $65.04/boe for 2025 compared to $71.60/boe for 2024 which was primarily a result of lower benchmark oil prices.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

PETROLEUM AND NATURAL GAS SALES

	Years Ended December 31		
($ thousands)	**2025**	2024	Change
Oil sales			
Light oil and condensate	**$ 366,523**	$ 421,383	$ (54,860)
Heavy oil	**1,261,899**	1,403,022	(141,123)
NGL	**29,583**	26,017	3,566
Total liquids sales	**1,658,005**	1,850,422	(192,417)
Natural gas sales	**26,643**	23,624	3,019
Total petroleum and natural gas sales	**1,684,648**	1,874,046	(189,398)
Blending and other expense	**(234,990)**	(263,943)	28,953
Total sales, net of blending and other expense [1] - continuing operations	**$ 1,449,658**	$ 1,610,103	$ (160,445)
Total sales - discontinued operations	**$ 1,888,524**	$ 2,334,909	$ (446,385)
Total sales, net of blending and other expense [1]	**$ 3,338,182**	$ 3,945,012	$ (606,830)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Total sales, net of blending and other expense for continuing operations was $1.4 billion for 2025 compared to $1.6 billion reported for 2024. The decrease in our realized pricing for 2025 relative to 2024 resulted in a $195.6 million decrease in total sales, net of blending and other expense which was partially offset by higher production which contributed to a $35.2 million increase in total sales, net of blending and other expense, relative to 2024.

Total sales from our discontinued operations were $1.9 billion in 2025 compared to $2.3 billion in 2024. The decrease in total sales prior to the disposition of our U.S. operations in December 2025 reflects lower production along with lower realized pricing in 2025 relative to 2024.

Total sales, net of blending and other expense of $3.3 billion for 2025 was $0.6 billion lower than $3.9 billion for 2024 which reflects lower benchmark oil prices and a decrease in daily production from the Eagle Ford operations prior to the disposition in December 2025.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary depending on the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands except for % and per boe)	**2025**	2024	Change
Royalties - continuing operations	**$ 203,833**	$ 261,205	$ (57,372)
Average royalty rate (1)(2) - continuing operations	**14.1%**	16.2%	(2.1%)
Royalties per boe (3) - continuing operations	**$ 8.52**	$ 11.16	$ (2.64)
Royalties - discontinued operations	**$ 508,305**	$ 618,881	$ (110,576)
Average royalty rate (1)(2) - discontinued operations	**26.9%**	26.5%	0.4%
Royalties per boe (3) - discontinued operations	**$ 17.51**	$ 18.98	$ (1.47)
Total royalties	**$ 712,138**	$ 880,086	$ (167,948)
Total average royalty rate (1)(2)	**21.3%**	22.3%	(1.0%)
Royalties per boe (3)	**$ 13.45**	$ 15.71	$ (2.26)

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Royalties for continuing operations were $203.8 million or 14.1% of total sales, net of blending and other expense for 2025 compared to $261.2 million or 16.2% in 2024. Total royalty expense for continuing operations was lower in 2025 due to lower total sales, net of blending and other expense, relative to 2024. Our average royalty rate of 14.1% for 2025 was lower than 16.2% for 2024 primarily due to lower benchmark commodity prices for oil.

Royalties for discontinued operations were $508.3 million or 26.9% of total sales in 2025 compared to $618.9 million or 26.5% of total sales in 2024. The decrease in royalties for discontinued operations in 2025 relative to 2024 reflects lower production and realized pricing prior to the disposition of our U.S. operations in December 2025.

Total royalties were $712.1 million or 21.3% of total sales, net of blending and other expense for 2025 which reflects lower realized pricing and production compared to 2024 when total royalties were $880.1 million or 22.3% of total sales, net of blending and other expense. Our total average royalty rate of 21.3% for 2025 was consistent with our annual guidance of approximately 22% for 2025. We expect our average royalty rate to be approximately 15% for 2026 which is consistent with 2025 and reflects the lower royalty rate applicable to our continuing Canadian operations.

OPERATING EXPENSE

	Years Ended December 31		
($ thousands except for per boe)	**2025**	2024	Change
Operating expense - continuing operations	**$ 334,317**	$ 336,069	$ (1,752)
Operating expense per boe (1) - continuing operations	**$ 13.98**	$ 14.36	$ (0.38)
Operating expense - discontinued operations	**$ 292,424**	$ 317,880	$ (25,456)
Operating expense per boe (1) - discontinued operations	**$ 10.07**	$ 9.75	$ 0.32
Total operating expense	**$ 626,741**	$ 653,949	$ (27,208)
Total operating expense per boe (1)	**$ 11.84**	$ 11.67	$ 0.17

(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Operating expense for continuing operations was $334.3 million ($13.98/boe) for 2025 compared to $336.1 million ($14.36/boe) for 2024. Total operating expense in 2025 was consistent with 2024 while per boe operating costs were lower which reflects our cost savings initiatives and production growth in 2025.

Operating expense for discontinued operations was $292.4 million ($10.07/boe) for 2025 compared to $317.9 million ($9.75/boe) in 2024. The decrease in total operating expense reflects lower production prior to the disposition of our U.S. operations in December 2025.

Lower production resulted in total operating expense of $626.7 million ($11.84/boe) for 2025 which was lower compared to $653.9 million ($11.67/boe) for 2024. Total operating expense of $11.84/boe for 2025 was consistent with our revised annual guidance of $11.75 - $12.00/boe. We expect annual operating expense of $13.75 - $14.25/boe for 2026 which is consistent with the 2025 results from our continuing Canadian operations.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary depending on trucking rates and hauling distances as we seek to optimize sales prices.

The following table compares our transportation expense for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands except for per boe)	**2025**	2024	Change
Transportation expense - continuing operations	**$ 83,697**	$ 84,211	$ (514)
Transportation expense per boe [1] - continuing operations	**$ 3.50**	$ 3.60	$ (0.10)
Transportation expense - discontinued operations	**$ 45,683**	$ 48,931	$ (3,248)
Transportation expense per boe [1] - discontinued operations	**$ 1.57**	$ 1.50	$ 0.07
Total transportation expense	**$ 129,380**	$ 133,142	$ (3,762)
Total transportation expense per boe [1]	**$ 2.44**	$ 2.38	$ 0.06

(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Transportation expense for continuing operations was $83.7 million ($3.50/boe) for 2025 which is consistent with $84.2 million ($3.60/boe) for 2024.

Transportation expense for discontinued operations was $45.7 million ($1.57/boe) for 2025 compared to $48.9 million ($1.50/boe) in 2024. The decrease in transportation expense reflects lower production from the Eagle Ford operations prior to closing the disposition in December 2025.

Total transportation expense of $129.4 million ($2.44/boe) in 2025 reflects lower production compared to 2024 when total transportation expense was $133.1 million ($2.38/boe). Total transportation expense of $2.44/boe in 2025 was consistent with our revised annual guidance of $2.40 - $2.55/boe for 2025. We expect annual transportation expense of $3.40 - $3.60/boe for 2026 which is consistent with our 2025 results from our continuing Canadian operations.

BLENDING AND OTHER EXPENSE

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense for continuing operations was $235.0 million for 2025 compared to $263.9 million for 2024. Lower blending and other expense is primarily a result of a decrease in the cost of condensate purchased for blending in 2025 compared to 2024.

FINANCIAL DERIVATIVES

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to reduce the volatility in our free cash flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are entered. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands)	**2025**	2024	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (26,896)**	$ (9,186)	$ (17,710)
Natural gas	**7,261**	10,633	(3,372)
Total	**$ (19,635)**	$ 1,447	$ (21,082)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ 530**	$ 7,548	$ (7,018)
Natural gas	**2,034**	(6,894)	8,928
Total	**$ 2,564**	$ 654	$ 1,910
Total financial derivatives gain (loss)			
Crude oil	**$ (26,366)**	$ (1,638)	$ (24,728)
Natural gas	**9,295**	3,739	5,556
Total	**$ (17,071)**	$ 2,101	$ (19,172)

We recorded a financial derivatives loss of $17.1 million for 2025 compared to a gain of $2.1 million for 2024. The realized financial derivatives loss of $19.6 million for 2025 resulted from $26.9 million of losses on crude oil contracts which was primarily related to WCS contracts outstanding during 2025 and was partially offset by $7.3 million of gains on natural gas contracts. The unrealized financial derivatives gain of $2.6 million for 2025 resulted from a $0.5 million gain on crude oil contracts and a $2.0 million gain on natural gas contracts. The fair value of our financial derivative contracts resulted in a net asset of $26.5 million at December 31, 2025 compared to a net asset of $23.9 million at December 31, 2024.

Refer to Note 19 of the consolidated financial statements for a complete listing of our outstanding contracts at March 4, 2026.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ per boe except for volume)	**2025**	2024	Change
Daily production (boe/d) - continuing operations	**65,528**	63,948	2 %
Daily production (boe/d) - discontinued operations	**79,551**	89,100	(11)%
Total production (boe/d)	**145,079**	153,048	(5)%
Operating netback:			
Total sales, net of blending and other expense [(1)]	**$ 60.61**	$ 68.79	$ (8.18)
Less:			
Royalties [(2)]	**(8.52)**	(11.16)	2.64
Operating expense [(2)]	**(13.98)**	(14.36)	0.38
Transportation expense [(2)]	**(3.50)**	(3.60)	0.10
Operating netback [(1)] - continuing operations	**$ 34.61**	$ 39.67	$ (5.06)
Operating netback [(1)] - discontinued operations	**$ 35.89**	$ 41.37	$ (5.48)
Operating netback [(1)]	**$ 35.31**	$ 40.67	$ (5.36)
Realized financial derivatives gain (loss) [(3)]	**(0.37)**	0.03	(0.40)
Operating netback after financial derivatives [(1)]	**$ 34.94**	$ 40.70	$ (5.76)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.
(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback for continuing operations of $34.61/boe for 2025 was lower than $39.67/boe for 2024 due to the decrease in our realized price, which resulted in lower per unit sales net of royalties. Combined operating and transportation expense for 2025 was consistent with 2024.

Operating netback for discontinued operations was $35.89/boe for 2025 which was lower than $41.37/boe for 2024 primarily due to lower realized prices. Our total operating netback for continuing and discontinued operations net of realized gains and losses on financial derivatives was $34.94/boe for 2025 compared to $40.70/boe for 2024.

Total operating netback after financial derivatives of $34.94/boe for 2025 reflects lower realized prices net of royalties compared to $40.70/boe for 2024.

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands except for per boe)	**2025**	2024 [1]	Change
Gross general and administrative expense - continuing operations	**$ 74,832**	$ 66,189	$ 8,643
Overhead recoveries - continuing operations	**(6,929)**	(7,826)	$ 897
General and administrative expense - continuing operations	**$ 67,903**	$ 58,363	$ 9,540
General and administrative expense per boe [2] - continuing operations	**$ 2.84**	$ 2.49	$ 0.35
General and administrative expense - discontinued operations [3]	**$ 35,622**	$ 23,383	$ 12,239
General and administrative expense per boe [2] - discontinued operations	**$ 1.23**	$ 0.72	$ 0.51
Total gross general and administrative expense	**$ 130,754**	$ 107,743	$ 23,011
Total overhead recoveries	**$ (27,229)**	$ (25,997)	$ (1,232)
Total general and administrative expense	**$ 103,525**	$ 81,746	$ 21,779
Total general and administrative expense per boe [2]	**$ 1.96**	$ 1.46	$ 0.50

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.
(2) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.
(3) General and administrative expense for discontinued operations is net of recoveries.

G&A expense for continuing operations of $67.9 million ($2.84/boe) for 2025 increased from $58.4 million ($2.49/boe) in 2024 due to increases in variable compensation related to the current and prior period, along with higher data systems costs and professional fees.

G&A expense for discontinued operations of $35.6 million ($1.23/boe) for 2025 was higher than $23.4 million ($0.72/boe) for 2024 due to severance costs related to the Eagle Ford disposition and higher costs related to information technology projects.

Total G&A expense of $103.5 million ($1.96/boe) for 2025 was consistent with expectations and above our revised annual guidance of $95 million ($1.76/boe) due to the severance costs related to the Eagle Ford disposition.

FINANCING AND INTEREST EXPENSE

Financing and interest expense includes interest on our credit facilities, the long-term notes and lease obligations as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands except for per boe)	**2025**	2024 (1)	Change
Interest on credit facilities	**$ 10,885**	$ 38,326	$ (27,441)
Interest on long-term notes	**149,214**	148,968	246
Interest on lease obligations	**1,333**	1,338	(5)
Cash interest - continuing operations	**$ 161,432**	$ 188,632	$ (27,200)
Amortization of debt issue costs	**56,116**	14,704	41,412
Accretion of asset retirement obligations	**19,114**	17,265	1,849
Net early redemption expense	**85,355**	24,350	61,005
Financing and interest expense - continuing operations	**$ 322,017**	$ 244,951	$ 77,066
Cash interest per boe (2) - continuing operations	**$ 6.75**	$ 8.06	$ (1.31)
Financing and interest expense per boe (2) - continuing operations	**$ 13.46**	$ 10.47	$ 2.99
Financing and interest expense - discontinued operations	**$ 22,985**	$ 23,423	$ (438)
Financing and interest expense per boe (2) - discontinued operations	**$ 0.79**	$ 0.72	$ 0.07
Total cash interest	**$ 174,116**	$ 206,104	$ (31,988)
Total cash interest per boe (2)	**$ 3.29**	$ 3.68	$ (0.39)
Total financing and interest expense	**$ 345,002**	$ 268,374	$ 76,628
Total financing and interest expense per boe (2)	**$ 6.52**	$ 4.79	$ 1.73

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.
(2) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Financing and interest expense for continuing operations reflects balances outstanding on our credit facilities in addition to principal amounts of long-term notes outstanding prior to repayment concurrent with closing of the Eagle Ford disposition.

Financing and interest expense for continuing operations was $322.0 million ($13.46/boe) in 2025 compared to $245.0 million ($10.47/boe) in 2024. Higher interest costs in 2025 relative to 2024 include costs incurred for the early redemption of the 8.50% senior notes in Q4/2025. Cash interest of $161.4 million ($6.75/boe) in 2025 reflects lower debt outstanding in addition to lower rates applicable to our credit facilities compared to 2024 when cash interest was $188.6 million ($8.06/boe). The weighted average interest rate applicable on our credit facilities was 6.7% in 2025 compared to 7.6% in 2024.

Accretion of asset retirement obligations of $19.1 million for 2025 was consistent with $17.3 million for 2024. Amortization of debt issue costs was higher in 2025 relative to 2024 primarily due to the de-recognition of deferred issuance costs associated with the long-term notes that were redeemed in Q4/2025. We also recorded an early redemption expense of $85.4 million in 2025 related to the redemption of the US$800 million 8.50% senior notes and the majority of the 7.375% senior notes. During 2024, Baytex recorded early redemption expense of $24.4 million related to the redemption of the 8.75% Senior Notes.

Total cash interest of $174.1 million ($3.29/boe) for 2025 was lower than our revised annual guidance of $180 million ($3.33/boe) due to lower debt balances following repayment of nearly all of our outstanding debt concurrent with closing of the Eagle Ford disposition.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense from continuing operations was $5.5 million for 2025 compared to $0.8 million for 2024.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved and probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the years ended December 31, 2025 and 2024.

	Years Ended December 31		
($ thousands except for per boe)	**2025**	2024 [(1)]	Change
Depletion and depreciation - continuing operations	**$ 484,932**	$ 483,314	$ 1,618
Depletion and depreciation per boe [(2)] - continuing operations	**$ 20.28**	$ 20.65	$ (0.37)
Depletion and depreciation - discontinued operations	**$ 779,760**	$ 902,596	$ (122,836)
Depletion and depreciation per boe [(2)] - discontinued operations	**$ 26.85**	$ 27.68	$ (0.83)
Total depletion and depreciation	**$ 1,264,692**	$ 1,385,910	$ (121,218)
Total depletion and depreciation per boe [(2)]	**$ 23.88**	$ 24.74	$ (0.86)

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.

(2) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Depletion and depreciation expense for continuing operations was $484.9 million ($20.28/boe) for 2025 which was consistent with $483.3 million ($20.65/boe) for 2024. Depletion and depreciation expense for discontinued operations was $779.8 million ($26.85/boe) for 2025 which was lower than $902.6 million ($27.68/boe) for 2024 which reflects lower production.

Total depletion and depreciation was $1.3 billion ($23.88/boe) for 2025 compared to $1.4 billion ($24.74/boe) for 2024. The decrease in total depletion and depreciation was primarily due to lower production from our U.S. operations prior to the disposition in December 2025.

IMPAIRMENT

At December 31, 2025, the Company assessed its oil and gas properties for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for three of five CGUs. The Company identified indicators of impairment for oil and gas properties in its Viking CGU due to negative technical revisions in proved plus probable reserves. The recoverable amount for the Viking CGU was not sufficient to support its carrying value which resulted in an impairment of $148.0 million recorded at December 31, 2025. The Company identified indicators of impairment reversal for oil and gas properties in its Lloydminster CGU due to a decrease in the asset-specific discount rate. The recoverable amount for the Lloydminster CGU supports its carrying value and no impairment reversal was recorded at December 31, 2025. The recoverable amount is based on a fair value less costs of disposal model using estimated cash flows associated with proved plus probable reserves from an independent reserve report prepared as at December 31, 2025 utilizing a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 14%.

At December 31, 2025, the recoverable amount of the two CGUs were calculated using the following benchmark reference prices for the years 2026 to 2035 adjusted for commodity differentials specific to the CGUs. The prices and costs subsequent to 2035 have been adjusted for inflation at an annual rate of 2.0%.

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WTI crude oil (US$/bbl)	59.92	65.10	70.28	71.93	73.37	74.84	76.34	77.87	79.42	81.01
WCS heavy oil ($/bbl)	65.13	70.43	76.90	78.71	80.29	81.90	83.53	85.20	86.91	88.65
Edmonton par oil ($/bbl)	77.54	83.60	90.17	92.32	94.17	96.06	97.98	99.93	101.93	103.97
AECO gas ($/mmbtu)	3.00	3.30	3.49	3.58	3.65	3.72	3.80	3.88	3.95	4.03

The following table demonstrates the sensitivity of the estimated recoverable amount of the Lloydminster and Viking CGUs to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment loss (reversal)	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Lloydminster CGU	$ 327,216	$ —	$ 27,250	$ 82,500	$ 500
Viking CGU	407,201	148,000	19,000	45,500	3,500

At December 31, 2024 and 2025, the Company assessed its exploration and evaluation assets for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of its CGUs.

SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with equity-settled awards is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with cash-settled awards is recognized in net income or loss over the vesting period of the awards with a corresponding share-based compensation liability. SBC expense varies with the quantity of unvested share awards outstanding and changes in the market price of our common shares.

We recorded SBC expense of $24.0 million for 2025 within our continuing operations compared to $11.9 million for 2024. SBC expense for 2025 reflects an increase in our share price which resulted in higher SBC expense relative to 2024.

FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Years Ended December 31		
($ thousands except for exchange rates)	**2025**	2024 (1)	Change
Unrealized foreign exchange (gain) loss	**$ (88,538)**	$ 153,930	$ (242,468)
Realized foreign exchange (gain) loss	**(5,481)**	1,965	(7,446)
Foreign exchange (gain) loss - continuing operations	**$ (94,019)**	$ 155,895	$ (249,914)
Foreign exchange gain - discontinued operations	**$ (3,624)**	$ —	$ (3,624)
Total foreign exchange gain	**$ (97,643)**	$ 155,895	$ (253,538)
CAD/USD exchange rates:			
At beginning of period	**1.4405**	1.3205	
At end of period	**1.3715**	1.4405	

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.

We recorded an unrealized foreign exchange gain of $88.5 million for 2025 within our continuing operations which reflects a decrease in the reported amount of the U.S. dollar denominated long-term notes and credit facilities due to a strengthening of the Canadian dollar relative to the U.S. dollar at the date of repayment in December 2025 compared to December 31, 2024. The unrealized foreign exchange loss of $153.9 million for 2024 is due an increase in the reported amount of the U.S dollar denominated long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at December 31, 2024 compared to December 31, 2023.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $5.5 million for 2025 within our continuing operations compared to a loss of $2.0 million for 2024.

We recorded a total foreign exchange gain of $97.6 million for 2025 compared to a loss of $155.9 million for 2024.

INCOME TAXES

	Years Ended December 31		
($ thousands)	**2025**	2024 [1]	Change
Current income tax expense	**$ 9,721**	$ 17,821	$ (8,100)
Deferred income tax expense	**114,014**	62,914	51,100
Income tax expense - continuing operations	**$ 123,735**	$ 80,735	$ 43,000
Income tax expense - discontinued operations	**$ (10,258)**	$ 55,958	$ (66,216)

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.

Current income tax expense for our continuing operations was $9.7 million for 2025 compared to $17.8 million recorded in 2024. Current income tax is lower in 2025 due to lower taxes incurred on the repatriation of earnings from the U.S. operations. We recorded deferred income tax expense of $114.0 million for 2025 compared to $62.9 million for 2024. The increase in deferred tax expense in 2025 primarily relates to the valuation allowance placed against our foreign tax attributes as a result of the sale of the Eagle Ford assets.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency ("CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada and we estimate it could take between two and three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During 2023, we purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent statement of account issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $244.2 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. First, the reassessments allege that the trusts were resettled and the resulting successor trusts were not able to access the losses of the predecessor trusts. Second, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. In September 2025, the Department of Justice, legal counsel for the Crown, abandoned the position that the trusts were resettled. The issue of whether the general anti-avoidance rule applies remains in dispute. If, after exhausting available appeals, the deduction of the Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potential penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

The following table summarizes our Canadian tax pools from continuing operations.

Canadian Tax Pools *($ thousands)*	**December 31, 2025**	December 31, 2024
Canadian oil and natural gas property expenditures	**$ 273,133**	$ 282,604
Canadian development expenditures	**608,073**	516,475
Undepreciated capital costs	**301,519**	282,056
Non-capital losses	**392,737**	447,993
Capital losses	**81,956**	60,493
Financing costs and other	**122,421**	71,670
Total Canadian tax pools	**$ 1,779,839**	$ 1,661,291

NET INCOME (LOSS) AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the years ended December 31, 2025 and 2024 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2025**	2024 [1]	Change
Petroleum and natural gas sales	**$ 1,684,648**	$ 1,874,046	$ (189,398)
Royalties	**(203,833)**	(261,205)	57,372
Revenue, net of royalties	**1,480,815**	1,612,841	(132,026)
Expenses			
Operating	**(334,317)**	(336,069)	1,752
Transportation	**(83,697)**	(84,211)	514
Blending and other	**(234,990)**	(263,943)	28,953
Operating netback [2]	**$ 827,811**	$ 928,618	$ (100,807)
General and administrative	**(67,903)**	(58,363)	(9,540)
Cash interest	**(161,432)**	(188,632)	27,200
Realized financial derivatives (loss) gain	**(19,635)**	1,447	(21,082)
Realized foreign exchange gain (loss)	**5,481**	(1,965)	7,446
Other income (expense)	**(7,970)**	5,141	(13,111)
Current income tax expense	**(9,721)**	(17,821)	8,100
Cash share-based compensation	**(24,041)**	(11,871)	(12,170)
Adjusted funds flow [3]	**$ 542,590**	$ 656,554	$ (113,964)
Transaction costs	**—**	(1,539)	1,539
Exploration and evaluation	**(5,534)**	(779)	(4,755)
Depletion and depreciation	**(484,932)**	(483,314)	(1,618)
Non-cash financing and interest	**(160,585)**	(56,319)	(104,266)
Unrealized financial derivatives gain (loss)	**2,564**	654	1,910
Unrealized foreign exchange gain (loss)	**88,538**	(153,930)	242,468
Gains on dispositions	**2,528**	4,134	(1,606)
Impairment	**(148,000)**	—	(148,000)
Deferred income tax (expense) recovery	**(114,014)**	(62,914)	(51,100)
Net income (loss) from continuing operations	**$ (276,845)**	$ (97,453)	$ (179,392)
Net income (loss) from discontinued operations	**$ (326,934)**	$ 334,050	$ (660,984)
Total net income (loss)	**$ (603,779)**	$ 236,597	$ (840,376)

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 of the consolidated financial statements for additional information.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(3) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow from continuing operations of $542.6 million for 2025 compared to $656.6 million for 2024. The decrease in adjusted funds flow for 2025 was primarily due to the decrease in realized pricing that resulted in lower revenues net of royalties partially offset by lower operating and transportation expense.

We reported a net loss from continuing operations of $276.8 million for 2025 compared to a net loss from continuing operations of $97.5 million for 2024. The net loss from continuing operations for 2025 includes an impairment loss along with higher financing and interest charges related to the Eagle Ford disposition, partially offset by an unrealized foreign exchange gain in 2025.

The total net loss for 2025 includes a $510.6 million loss recorded on the Eagle Ford disposition which includes a $866.7 million reclassification of the cumulative foreign exchange gain associated with discontinued operations.

OTHER COMPREHENSIVE (LOSS) INCOME

Other comprehensive (loss) income reflects the foreign currency translation adjustment on the U.S. net assets prior to disposition in December 2025 which is not recognized in net income or loss. The foreign currency translation loss of $213.2 million for 2025 relates to the change in value of our U.S. net assets and is mainly due to the strengthening of the Canadian dollar relative to the U.S. dollar at the date of the Eagle Ford disposition compared to December 31, 2024. The CAD/USD exchange rate was 1.3764 CAD/USD at December 18, 2025 compared to 1.4405 CAD/USD at December 31, 2024.

CAPITAL EXPENDITURES

Capital expenditures for the years ended December 31, 2025 and 2024 are summarized as follows.

	Years Ended December 31		
($ thousands)	**2025**	2024	Change
Drilling, completion and equipping	**$ 478,710**	$ 399,817	$ 78,893
Facilities and other	**69,642**	89,669	(20,027)
Exploration and development expenditures - continuing operations	**$ 548,352**	$ 489,486	$ 58,866
Exploration and development expenditures - discontinued operations	**657,719**	767,147	$ (109,428)
Total exploration and development expenditures	**$ 1,206,071**	$ 1,256,633	$ (50,562)
Property acquisitions - continuing operations	**$ 30,151**	$ 48,889	$ (18,738)
Proceeds from dispositions - continuing operations	**$ (11,953)**	$ (41,149)	$ 29,196
Property acquisitions - discontinued operations	**$ 1,867**	$ 3,526	$ (1,659)
Proceeds from dispositions - discontinued operations	**$ (3,011,350)**	$ (5,346)	$ (3,006,004)

Exploration and development expenditures for continuing operations were $548.4 million in 2025 compared to $489.5 million in 2024. Drilling and completion spending of $478.7 million in 2025 was higher than $399.8 million in 2024 which reflects increased development activity on our Duvernay light oil properties and Lloydminster heavy oil properties.

Exploration and development expenditures on the U.S. operations of $657.7 million for 2025 reflects lower activity on the non-operated Eagle Ford properties prior to closing of the disposition on December 19, 2025 compared to 2024 when exploration and development expenditures were $767.1 million.

Total exploration and development expenditures of $1.21 billion for 2025 were consistent with our revised annual guidance of approximately $1.2 billion. We expect annual exploration and development expenditures of $550 - $625 million for 2026 which is designed to generate production growth in our heavy and light oil operations.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong financial position that provides flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At December 31, 2025, our capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash and the credit facilities.

In order to manage our capital structure and liquidity, we may from time-to-time issue or repurchase equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected liquidity. There is no certainty that any of these additional sources of capital would be available if required.

At December 31, 2025 we had net cash[(1)] of $765.8 million compared to net debt[(1)] of $2.4 billion at December 31, 2024 which reflects the repayment of our Credit Facilities, all of the 8.50% Senior Notes and the majority of the 7.375% Senior Notes concurrent with the sale of the Eagle Ford assets. Free cash flow[(2)] of $274.9 million generated in 2025 was allocated to debt repayment along with $98.0 million of shareholder returns including share buybacks and quarterly dividends.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Credit Facilities

At closing of the Eagle Ford asset sale, on December 19, 2025 we modified our credit facilities (the "Credit Facilities") to decrease the committed amount to $750.0 million from US$1.1 billion and extend maturity from June 27, 2029 to June 27, 2030. There were no changes to the financial covenants as a result of the modification.

There are no mandatory principal payments required prior to maturity which could be extended upon our request. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances under the Baytex Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the Canadian Prime Rate, U.S. Base Rate, Canadian Overnight Repo Rate Average rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 6.7% for 2025, which is lower than 7.6% for 2024 due to lower applicable benchmark rates.

At December 31, 2025, Baytex had $4.4 million of outstanding letters of credit (December 31, 2024 - $5.8 million outstanding) under the Credit Facilities.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at December 31, 2025.

Covenant Description	Position as at December 31, 2025	Covenant
Senior Secured Debt [(1)] to Bank EBITDA [(2)] (Maximum Ratio)	**0.0:1.0**	3.5:1.0
Interest Coverage [(3)] (Minimum Ratio)	**4.4:1.0**	3.5:1.0
Total Debt [(4)] to Bank EBITDA [(2)] (Maximum Ratio)	**0.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2025, the Company's Senior Secured Debt totaled $5.8 million.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended December 31, 2025 was $712.4 million.
(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Financing and interest expenses for the twelve months ended December 31, 2025 were $160.1 million.
(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at December 31, 2025, our Total Debt was $101.7 million.

Long-Term Notes

During 2025, Baytex repurchased and cancelled all of the US$800.0 million principal amount of the 8.50% Senior Notes at 105.205% of par value, and US$505.0 million principal amount of the 7.375% Senior Notes at 103.807% of par value. At December 31, 2025 there was US$70.0 million aggregate principal amount of the 7.375% Senior Notes outstanding.

The 7.375% Senior Notes were issued on April 1, 2024 and US$70.0 million remains outstanding as of December 31, 2025. The 7.375% Senior Notes mature on March 15, 2032 and are redeemable at our option, in whole or in part, at specified redemption prices on or after March 15, 2027 and will be redeemable at par from March 15, 2029 to maturity.

Baytex is subject to certain financial and commercial covenants related to its Credit Facilities and long-term notes. Noncompliance with these covenants may result in an event of default, at which point the carrying value of the debt could become repayable within a 12 month period after the reporting date.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the year ended December 31, 2025, we issued 0.1 million common shares pursuant to our share-based compensation program. As at December 31, 2025, we had 765.6 million common shares issued and outstanding and no preferred shares issued and outstanding. As at March 2, 2026 there were 740.1 million common shares issued and outstanding and no preferred shares issued and outstanding.

During the year ended December 31, 2025, we repurchased 8.1 million common shares under our normal course issuer bid ("NCIB") at an average price of $3.55 per share for total consideration of $28.9 million. At December 31, 2025, we had 62.8 million shares remaining on our NCIB which expires on July 2, 2025. We have obtained an exemption order from the Canadian securities regulators which permits us to purchase its common shares through the NYSE and other U.S. based trading systems.

For the year ended December 31, 2025 we recorded a $0.5 million charge to shareholders’ capital related to the federal tax on equity repurchases (December 31, 2024 - $4.3 million).

Our shareholder returns include a quarterly dividend of $0.0225 per share. Total dividends of $69.2 million were declared during 2025. On March 4, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2026 for shareholders of record on March 13, 2026. These dividends are designated as “eligible dividends” for Canadian income tax purposes. For U.S. income tax purposes, Baytex’s dividends are considered “qualified dividends.”

Contractual Obligations and Contingencies

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2025 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	2026	2027-2028	2029-2030	2031 and beyond
Credit Facilities - principal	**$ 1,400**	$ —	$ —	$ 1,400	$ —
Long-term notes - principal	**95,947**	—	—	—	95,947
Interest on long-term notes (1)	**43,929**	7,076	14,152	14,152	8,549
Lease obligations - principal	**26,274**	8,487	10,690	7,097	—
Processing agreements	**4,969**	948	563	533	2,925
Transportation agreements	**134,312**	40,249	51,388	13,416	29,259
Total	**$ 306,831**	$ 56,760	$ 76,793	$ 36,598	$ 136,680

(1) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

The Company is, from time-to-time, subject to various claims, demands, audits and other proceedings covering matters that arise in the ordinary course of business activities. Such claims and other proceedings often relate to labour, tax, personal injury, environmental, title or commercial matters. Baytex retains liability for matters related to our prior ownership of assets located in the U.S. Resolution of these matters may have an unfavorable financial or operating impact on the Company. Certain conditions may exist as at December 31, 2025 which may result in a loss to the Company. However, the Company believes that none of these matters are expected to have a material effect on the results of operations or financial position of the Company.

The Company establishes legal provisions for known and potential claims for which payment is probable and can be reliably estimated. The Company also has comprehensive liability insurance coverage; however such insurance does not cover all risks to which we might be exposed and in other cases, may only partially cover losses incurred by the Company.

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2025			2024		
($ thousands except for per boe)	**Canada**	**Discontinued Operations[1]**	**Total**	Canada	Discontinued Operations[1]	Total
Total daily production						
Light oil and condensate (bbl/d)	**12,031**	**42,109**	**54,140**	11,568	53,093	64,661
Heavy oil (bbl/d)	**42,628**	**—**	**42,628**	42,227	—	42,227
NGL (bbl/d)	**4,488**	**13,524**	**18,012**	3,519	17,689	21,208
Total liquids (bbl/d)	**59,147**	**55,633**	**114,780**	57,314	70,782	128,096
Natural gas (mcf/d)	**48,895**	**84,950**	**133,845**	48,113	100,679	148,792
Total production (boe/d)	**67,295**	**69,792**	**137,087**	65,332	87,562	152,894
Operating netback ($/boe)						
Light oil and condensate ($/bbl) [2]	**$ 75.88**	**$ 81.66**	**$ 80.38**	$ 93.66	$ 97.05	$ 96.44
Heavy oil, net of blending and other expense ($/bbl) [3]	**58.62**	**—**	**58.62**	70.05	—	70.05
NGL ($/bbl) [2]	**19.89**	**24.87**	**23.63**	26.06	29.70	29.09
Natural gas ($/mcf) [2]	**2.10**	**3.96**	**3.28**	1.43	3.02	2.50
Total sales, net of blending and other per boe [3]	**$ 53.55**	**$ 58.91**	**$ 56.28**	$ 64.31	$ 68.31	$ 66.60
Royalties per boe [4]	**(6.97)**	**(15.96)**	**(11.54)**	(10.05)	(18.16)	(14.69)
Operating expense per boe [4]	**(13.84)**	**(11.22)**	**(12.51)**	(13.12)	(8.29)	(10.36)
Transportation expense per boe [4]	**(3.44)**	**(1.46)**	**(2.43)**	(3.59)	(1.43)	(2.35)
Operating netback per boe [3]	**$ 29.30**	**$ 30.27**	**$ 29.80**	$ 37.55	$ 40.43	$ 39.20
Financial						
Petroleum and natural gas sales	**$ 381,556**	**$ 378,259**	**$ 759,815**	$ 466,706	$ 550,311	$ 1,017,017
Royalties	**(43,132)**	**(102,449)**	**(145,581)**	(60,396)	(146,279)	(206,675)
Revenue, net of royalties	**$ 338,424**	**$ 275,810**	**$ 614,234**	$ 406,310	$ 404,032	$ 810,342
Operating	**(85,708)**	**(72,026)**	**(157,734)**	(78,878)	(66,812)	(145,690)
Transportation	**(21,314)**	**(9,352)**	**(30,666)**	(21,595)	(11,515)	(33,110)
Blending and other	**(50,039)**	**—**	**(50,039)**	(80,148)	—	(80,148)
Operating netback [3]	**$ 181,363**	**$ 194,432**	**$ 375,795**	$ 225,689	$ 325,705	$ 551,394
General and administrative	**—**	**—**	**(34,963)**	—	—	(20,433)
Cash interest	**—**	**—**	**(38,581)**	—	—	(48,769)
Realized financial derivatives gain (loss)	**—**	**—**	**1,013**	—	—	(2,115)
Other	**—**	**—**	**(41,733)**	—	—	(18,191)
Adjusted funds flow [5]	**$ 181,363**	**$ 194,432**	**$ 261,531**	$ 225,689	$ 325,705	$ 461,886
Net (loss) income	**$ (163,790)**	**$ (465,994)**	**$ (856,887)**	$ 113,551	$ 113,172	$ (38,477)
Exploration and development expenditures	**$ 92,720**	**$ 81,358**	**$ 174,078**	$ 108,971	$ 89,206	$ 198,177
Property acquisitions	**5,217**	**327**	**5,544**	12,305	316	12,621
Proceeds from dispositions	**(159)**	**(3,011,899)**	**(3,012,058)**	(41,517)	(822)	(42,339)
Net (cash) debt [5]			**$ (765,785)**			$ 2,417,172

(1) Discontinued operations reflects the operating and financial results from the Eagle Ford assets prior to disposition on December 19, 2025. Refer to Note 7 of the consolidated financial statements for additional information.

(2) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

(3) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(4) Calculated as royalties expense, operating expense or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

(5) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

	Three Months Ended December 31		
	2025	2024	Change
Benchmark Averages			
WTI oil (US$/bbl) [1]	**59.14**	70.27	(11.13)
Edmonton par oil ($/bbl) [2]	**76.49**	94.98	(18.49)
Edmonton par oil differential to WTI (US$/bbl)	**(4.30)**	(2.39)	(1.91)
WCS heavy oil ($/bbl) [3]	**66.88**	80.77	(13.89)
WCS heavy oil differential to WTI (US$/bbl)	**(11.19)**	(12.54)	1.35
AECO 7A natural gas price ($/mcf) [4]	**2.34**	1.46	0.88
AECO 5A natural gas price ($/mcf) [5]	**2.23**	1.48	0.75
CAD/USD average exchange rate	**1.3949**	1.3992	(0.0043)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(3) WCS refers to the average posting price for the benchmark WCS heavy oil.
(4) AECO 7A refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) AECO 5A refers to the AECO arithmetic average daily index price published by the Canadian Gas Price Reporter ("CGPR").

Continuing Operations

We invested $92.7 million on exploration and development in Q4/2025 and generated production of 67,295 boe/d which was 1,963 boe/d higher than 65,332 boe/d reported for Q4/2024 when we invested $109.0 million on exploration and development. The increase in production reflects our successful heavy oil development program and Duvernay production growth which more than offset the impact of the Q4/2024 disposition of 2,000 boe/d of heavy oil production from Kerrobert Thermal.

Lower light and heavy oil benchmark pricing resulted in a realized price of $53.55/boe for Q4/2025 which was $10.76/boe lower than $64.31/boe for Q4/2024. Operating netback[1] of $181.4 million ($29.30/boe) for Q4/2025 reflects lower realized pricing relative to Q4/2024 when we reported operating netback of $225.7 million ($37.55/boe) for our Canadian operations.

Discontinued Operations

In the U.S., exploration and development expenditures were $81.4 million and production averaged 69,792 boe/d for Q4/2025 which is 17,770 boe/d lower than 87,562 boe/d reported for Q4/2024 when we spent $89.2 million. Lower production in Q4/2025 relative to Q4/2024 reflects reduced activity on the non-operated Eagle Ford property along with the disposition of the U.S. assets on December 19, 2025.

The MEH benchmark averaged US$60.70/bbl in Q4/2025 which was US$11.70/boe lower than US$72.40/bbl during Q4/2024 and resulted in a realized price of $58.91/boe which was $9.40/boe lower than our realized price of $68.31/boe in Q4/2024. Operating netback of $194.4 million ($30.27/boe) was $131.3 million ($10.16/boe) lower than $325.7 million ($40.43/boe) for Q4/2024 which reflects lower benchmark commodity prices along with the disposition of the Eagle Ford assets on December 19, 2025.

Total Q4/2025 Financial Results

We generated adjusted funds flow[2] of $261.5 million in Q4/2025 compared to $461.9 million in Q4/2024. The decrease in adjusted funds flow for Q4/2025 relative to Q4/2024 reflects lower benchmark pricing and the disposition of the U.S. operations on December 19, 2025. Proceeds from the disposition were used to repay all of our outstanding credit facilities and the majority of the long-term notes which resulted in net cash[2] was $765.8 million at Q4/2025 compared to net debt of $2.4 billion in Q4/2024.

We recorded a net loss of $856.9 million in Q4/2025 compared to net loss of $38.5 million in Q4/2024. The net loss for Q4/2025 includes the $510.6 million loss on the Eagle Ford disposition recorded net of the cumulative foreign exchange gain along with a $148.0 million impairment loss on our Viking CGU due to changes in proved plus probable reserves.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

QUARTERLY FINANCIAL INFORMATION

	2025				2024			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Total petroleum and natural gas sales	**759,815**	927,648	886,579	999,130	1,017,017	1,074,623	1,133,123	984,192
Net (loss) income - continuing operations (3)	**(334,057)**	(28,451)	103,018	(17,355)	(124,903)	96,204	13,751	(82,505)
Per common share - basic	**(0.43)**	(0.04)	0.13	(0.02)	(0.16)	0.12	0.02	(0.10)
Per common share - diluted	**(0.43)**	(0.04)	0.13	(0.02)	(0.16)	0.12	0.02	(0.10)
Total net (loss) income	**(856,887)**	31,968	151,549	69,591	(38,477)	185,219	103,898	(14,043)
Per common share - basic	**(1.12)**	0.04	0.20	0.09	(0.05)	0.23	0.13	(0.02)
Per common share - diluted	**(1.12)**	0.04	0.20	0.09	(0.05)	0.23	0.13	(0.02)
Adjusted funds flow (1)	**261,531**	422,232	366,919	463,870	461,886	537,947	532,839	423,846
Per common share - basic	**0.34**	0.55	0.48	0.60	0.59	0.68	0.65	0.52
Per common share - diluted	**0.34**	0.55	0.48	0.60	0.59	0.67	0.65	0.52
Free cash flow (2)	**76,486**	142,688	3,188	52,529	254,838	220,159	180,673	(88)
Per common share - basic	**0.10**	0.19	—	0.07	0.33	0.28	0.22	—
Per common share - diluted	**0.10**	0.18	—	0.07	0.33	0.28	0.22	—
Cash flows from operating activities	**227,657**	472,676	354,312	431,317	468,865	550,042	505,584	383,773
Per common share - basic	**0.30**	0.62	0.46	0.56	0.60	0.69	0.62	0.47
Per common share - diluted	**0.30**	0.61	0.46	0.56	0.60	0.69	0.62	0.47
Dividends declared	**17,268**	17,326	17,304	17,289	17,598	17,732	18,161	18,494
Per common share – basic	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Exploration and development expenditures	**174,078**	270,364	356,532	405,097	198,177	306,332	339,573	412,551
Canada	**92,720**	123,579	147,734	184,319	108,971	120,473	101,916	158,126
U.S.	**81,358**	146,785	208,798	220,778	89,206	185,859	237,657	254,425
Property acquisitions	**5,544**	24,024	1,193	1,257	12,621	1,042	3,349	35,403
Proceeds from dispositions	**(3,012,058)**	(8,254)	(725)	(2,266)	(42,339)	(1,436)	(2,695)	(25)
Net (cash) debt (1)	**(765,785)**	2,244,358	2,293,940	2,390,250	2,417,172	2,493,269	2,639,014	2,639,841
Total assets	**3,345,414**	7,601,389	7,552,013	7,824,576	7,759,745	7,614,157	7,770,926	7,717,495
Common shares outstanding	**765,568**	768,317	768,317	770,039	773,590	787,328	804,977	821,322
Daily production								
Total production (boe/d)	**137,087**	150,950	148,095	144,194	152,894	154,468	154,194	150,620
Continuing operations (boe/d)	**67,295**	68,185	64,167	62,380	65,332	64,668	63,688	62,081
Discontinued operations (boe/d)	**69,792**	82,765	83,928	81,814	87,562	89,800	90,506	88,540
Benchmark prices								
WTI oil (US$/bbl)	**59.14**	64.93	63.74	71.42	70.27	75.10	80.57	76.96
WCS heavy ($/bbl)	**66.88**	75.14	74.10	84.33	80.77	83.98	91.72	77.73
Edmonton Light ($/bbl)	**76.49**	86.20	84.15	95.27	94.98	97.91	105.30	92.16
CAD/USD avg exchange rate	**1.3949**	1.3774	1.3840	1.4350	1.3992	1.3636	1.3684	1.3488
AECO gas ($/mcf)	**2.34**	1.00	2.07	2.02	1.46	0.81	1.44	2.05
Total sales, net of blending and other expense ($/boe) (2)	**56.28**	63.22	61.16	71.38	66.60	71.97	75.93	67.12
Royalties ($/boe) (4)	**(11.54)**	(13.05)	(13.16)	(16.02)	(14.69)	(15.75)	(17.14)	(15.26)
Operating expense ($/boe) (4)	**(12.51)**	(11.54)	(11.95)	(11.38)	(10.36)	(11.76)	(11.95)	(12.65)
Transportation expense ($/boe) (4)	**(2.43)**	(2.54)	(2.44)	(2.35)	(2.35)	(2.60)	(2.37)	(2.18)
Operating netback ($/boe) (2)	**29.80**	36.09	33.61	41.63	39.20	41.86	44.47	37.03
Financial derivatives gain (loss) ($/boe) (4)	**0.08**	(0.62)	(0.88)	(0.01)	(0.15)	0.02	(0.16)	0.40
Operating netback after financial derivatives ($/boe) (2)	**29.88**	35.47	32.73	41.62	39.05	41.88	44.31	37.43

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Previously disclosed amounts have been revised to conform with current period presentation.
(4) Calculated as royalties expense, operating expenses, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our results for the previous eight quarters reflect the disciplined execution of our capital programs while oil and natural gas prices have fluctuated along with acquisition and disposition activity. Production of 137,087 boe/d in Q4/2025 reflects the Eagle Ford disposition on December 19, 2025 which resulted in lower reported production compared to an average of approximately 151,000 boe/d over the previous seven quarters presented. Our successful light and heavy oil development programs in Canada resulted in production of 67,295 boe/d for Q4/2025 compared to 62,081 boe/d in Q1/2024 despite the Kerrobert Thermal disposition completed in Q4/2024.

Benchmark prices for crude oil have declined over the previous eight quarters due to increasing supply from OPEC+ and North American production growth along with concerns over slowing global economic activity. Lower benchmark prices resulted in realized pricing of $56.28/boe for Q4/2025 and operating netback after financial derivatives of $29.88/boe. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow(1) of $261.5 million and cash flows from operating activities of $227.7 million for Q4/2025 reflect the disposition of the Eagle Ford assets on December 19, 2025 along with our realized pricing.

On December 19, 2025, we completed the disposition of the Eagle Ford assets which resulted in a net cash(1) position of $765.8 million at Q4/2025 compared to a net debt position of $2.6 billion at Q1/2024. The change in net (cash) debt also reflects free cash flow(2) of $930.6 million generated in the period since Q1/2024, along with $366.4 million allocated to shareholder returns.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the AIF for the year ended December 31, 2025 for a full description of the risks associated with these regulations and how they may impact our business in the future.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released voluntary standards for reporting periods starting on or after January 1, 2025 that are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators ("CSA") have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. In April 2025, the CSA announced it is pausing development of new sustainability reporting requirements to allow issuers to adapt to recent developments in the U.S. and globally. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any material financial arrangements that are excluded from the consolidated financial statements as at December 31, 2025, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and NGL reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the estimation of recoverable amount for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by an independent qualified reserves evaluator and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the estimation of recoverable amount estimates for non-financial assets.

Cash-generating Units

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. These indicators can be internal such as changes in estimated proved plus probable oil and gas reserves and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

Measurement of Recoverable Amounts

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim wells and facilities, the estimated time period during which these costs will be incurred in the future, and risk-free discount rates and inflation rates derived from observable market data. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. The timing of asset retirement obligation expenditures may occur earlier than estimated. The timing of asset retirement obligations is supported by externally evaluated reserves with consideration by the Company of regulatory requirements.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This MD&A also contains the terms "adjusted funds flow" and "net (cash) debt" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense and heavy oil, net of blending and other expense

Total sales, net of blending and other expense and heavy oil, net of blending and other expense represent the total revenues and heavy oil revenues realized from produced volumes during a period, respectively. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. Heavy oil, net of blending and other expense is calculated as heavy oil sales less blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

The following table reconciles heavy oil, net of blending and other expense to amounts disclosed in the primary financial statements from continuing operations.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Petroleum and natural gas sales	**$ 381,556**	$ 437,905	$ 466,706	**$ 1,684,648**	$ 1,874,046
Light oil and condensate [1]	**(83,991)**	(99,188)	(99,679)	**(366,523)**	(421,383)
NGL [1]	**(8,212)**	(7,250)	(8,438)	**(29,583)**	(26,017)
Natural gas sales [1]	**(9,424)**	(2,462)	(6,310)	**(26,643)**	(23,624)
Heavy oil sales	**$ 279,929**	$ 329,005	$ 352,279	**$ 1,261,899**	$ 1,403,022
Blending and other expense - heavy oil [2]	**(50,039)**	(49,750)	(80,148)	**(234,990)**	(263,943)
Heavy oil, net of blending and other expense - continuing operations	**$ 229,890**	$ 279,255	$ 272,131	**$ 1,026,909**	$ 1,139,079

(1) Component of petroleum and natural gas sales; see Note 15 Petroleum and Natural Gas Sales in the consolidated financial statements for the year ended December 31, 2025 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales from continuing operations.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Petroleum and natural gas sales	**$ 381,556**	$ 437,905	$ 466,706	**$ 1,684,648**	$ 1,874,046
Blending and other expense	**(50,039)**	(49,750)	(80,148)	**(234,990)**	(263,943)
Total sales, net of blending and other expense	**$ 331,517**	$ 388,155	$ 386,558	**$ 1,449,658**	$ 1,610,103
Royalties	**(43,132)**	(53,645)	(60,396)	**(203,833)**	(261,205)
Operating expense	**(85,708)**	(84,994)	(78,878)	**(334,317)**	(336,069)
Transportation expense	**(21,314)**	(23,060)	(21,595)	**(83,697)**	(84,211)
Operating netback - continuing operations	**$ 181,363**	$ 226,456	$ 225,689	**$ 827,811**	$ 928,618
Realized financial derivatives gain (loss) [1]	**1,013**	(8,580)	(2,115)	**(19,635)**	1,447
Operating netback after realized financial derivatives - continuing operations	**$ 182,376**	$ 217,876	$ 223,574	**$ 808,176**	$ 930,065

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 19 Financial Instruments and Risk Management in the consolidated financial statements for the year ended December 31, 2025 for further information.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and transaction costs.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2025**	September 30, 2025	December 31, 2024	**2025**	2024
Cash flows from operating activities	**$ 227,657**	$ 472,676	$ 468,865	**$ 1,485,962**	$ 1,908,264
Change in non-cash working capital	**(226)**	(55,961)	(13,428)	**(18,111)**	17,922
Transaction costs	**26,383**	—	—	**26,383**	1,539
Additions to exploration and evaluation assets	**—**	—	—	**(930)**	—
Additions to oil and gas properties	**(174,078)**	(270,364)	(198,177)	**(1,205,141)**	(1,256,633)
Payments on lease obligations	**(3,250)**	(3,663)	(2,422)	**(13,272)**	(15,510)
Free cash flow	**$ 76,486**	$ 142,688	$ 254,838	**$ 274,891**	$ 655,582

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP measure that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net (cash) debt

We use net (cash) debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net (cash) debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net (cash) debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash, trade receivables, and prepaids and other assets.

The following table summarizes our calculation of net (cash) debt.

($ thousands)	As at December 31, 2025	September 30, 2025	December 31, 2024
Credit Facilities	**$ 1,138**	$ 166,841	$ 324,346
Unamortized debt issuance costs - Credit Facilities (1)	**262**	15,504	16,861
Long-term notes	**93,834**	1,815,230	1,932,890
Unamortized debt issuance costs - Long-term notes (1)	**2,113**	40,375	47,729
Trade payables	**236,373**	554,057	512,473
Share-based compensation liability	**34,802**	24,666	24,732
Dividends payable	**17,268**	17,326	17,598
Other long-term liabilities	**—**	20,163	20,887
Cash	**(953,113)**	(10,417)	(16,610)
Trade receivables	**(135,230)**	(324,287)	(387,266)
Prepaids and other assets	**(63,232)**	(75,100)	(76,468)
Net (cash) debt	**$ (765,785)**	$ 2,244,358	$ 2,417,172

(1) Unamortized debt issuance costs were obtained from Note 9 Credit Facilities and Note 10 Long-term Notes from the consolidated financial statements for the year ended December 31, 2025. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirements obligations settled during the applicable period, transaction costs and cash premiums on derivatives.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended			Years Ended December 31	
($ thousands)	December 31, 2025	September 30, 2025	December 31, 2024	2025	2024
Cash flows from operating activities	**$ 227,657**	$ 472,676	$ 468,865	**$ 1,485,962**	$ 1,908,264
Change in non-cash working capital	**(226)**	(55,961)	(13,428)	**(18,111)**	17,922
Asset retirement obligations settled	**7,717**	5,517	6,449	**20,318**	28,793
Transaction costs	**26,383**	—	—	**26,383**	1,539
Adjusted funds flow	**$ 261,531**	$ 422,232	$ 461,886	**$ 1,514,552**	$ 1,956,518

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2025, an evaluation was conducted to determine the effectiveness of our “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2025.

The effectiveness of our internal control over financial reporting as of December 31, 2025 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2025 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

($ thousands, except per common share amounts)	**2025**	2024	2023
Revenues, net of royalties - continuing operations	**1,480,815**	1,612,841	1,515,873
Total revenues, net of royalties	**2,861,034**	3,328,869	2,712,829
Adjusted funds flow (1)	**1,514,552**	1,956,518	1,594,350
Per common share - basic	**1.97**	2.44	2.26
Per common share - diluted	**1.97**	2.42	2.26
Net (loss) income - continuing operations	**(276,845)**	(97,453)	(40,641)
Per common share - basic	**(0.36)**	(0.12)	(0.06)
Per common share - diluted	**(0.36)**	(0.12)	(0.06)
Total net (loss) income	**(603,779)**	236,597	(233,356)
Per common share - basic	**(0.78)**	0.29	(0.33)
Per common share - diluted	**(0.78)**	0.29	(0.33)
Dividends declared	**69,187**	71,985	37,519
Per common share – basic	**0.090**	0.090	0.045
Total assets	**3,345,414**	7,759,745	7,460,931
Credit facilities - principal	**1,400**	341,207	864,736
Long-term notes - principal	**95,947**	1,980,619	1,597,475
Total sales, net of blending and other expense ($/boe) (2)	**63.04**	70.43	70.82
Total production (boe/d)	**145,079**	153,048	122,154

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our 2026 guidance for: exploration and development expenditures, average daily production, royalty rate and operating expense, transportation expense, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; the expected time to resolve the reassessment of our tax filings by the Canada Revenue Agency; that our exploration and development spending in 2026 is designed to generate production growth and support our development plans; our objective to maintain a strong financial position to execute development programs, deliver shareholder returns and optimize our portfolio through strategic acquisitions; that we may from time to time, issue or repurchase debt or equity securities, enter into business transactions or adjust capital spending to manage liquidity; our intent to fund certain financial obligations with cash flow from operations, the expected timing of the financial obligations and the potential for losses associated with claims. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; that we will have sufficient financial resources in the future to provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices (including as a result of tariffs); risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Company and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2025, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2026 and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

The future acquisition of our common shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Company has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback, if any, in the future.

Baytex's future shareholder distributions, including but not limited to the payment of dividends, if any, and the level thereof is uncertain. Any decision to pay dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith and any special dividends) will be subject to the discretion of the Board of Directors of Baytex and may depend on a variety of factors, including, without limitation, Baytex's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on Baytex under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend is subject to the discretion of the Board of Directors of Baytex.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial and operational results. Listed below is a description of these risks and uncertainties.

Risks Relating to Our Business and Operations

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Company's business, results of operations, or cash flows and financial condition

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, OPEC+, the condition of the Canadian, United States, European and Asian economies, the impacts of geopolitical events, including the Russian Ukrainian war, geopolitical developments in Venezuela and conflicts and hostilities in the Middle East, the imposition of tariffs or other adverse economic or political development in the United States, Europe, the Middle East, Africa, South America or Asia, the impact of pandemics/epidemics, government regulation, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas.

In particular, tariffs or other restrictive measures or countermeasures affecting trade between Canada and the United States and between the United States and other countries, if implemented for any period of time, could have a significant impact on the market for oil and natural gas products, especially with respect to oil and gas produced in Canada, and could result in, among other things, price volatility, an increase to the cost of materials used in oil and gas operations, a relative weakening of the Canadian dollar, widening differentials, and decreased demand due to lower economic activity. For more information with respect to tariffs, see "*Industry Conditions - Tariffs*" in the AIF for the year ended December 31, 2025.

All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium crude oil and heavy crude oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, storage capacity, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. In addition, there is not sufficient pipeline capacity for Canadian crude oil to access the American refinery complex or tidewater to access world markets and the availability of additional transport capacity via rail is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages, which contributes to this volatility.

Decreases to or prolonged periods of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

Our success is highly dependent on our ability to develop existing properties and add to our oil and natural gas reserves

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced. As a result, our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient hydrocarbons to return a profit. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays or failure in obtaining governmental, landowner or other stakeholder approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow from operating activities to varying degrees.

There is no assurance we will be successful in developing our reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserve life of our properties will decline, which may adversely affect our business, financial condition, results of operations and prospects.

The amount of oil and natural gas that we can produce and sell is subject to the availability and cost of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems to which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. In addition, many of the pipeline systems that we use are controlled by a single company and rates are set through a regulatory process, as a result we are subject to the outcome of those regulatory processes. Any significant change in market factors, regulatory decisions or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

Access to the pipeline capacity for the export of crude oil from Canada has, at times, been inadequate for the amount of Canadian production being exported. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term take-away capacity or that currently operating systems will remain in service. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather, derailment or blockades and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may be processed through facilities controlled by third parties. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Water use restrictions and/or limited access to water or other fluids may impact the Company's ability to fracture its wells or carry out waterflood operations

The Company undertakes or intends to undertake certain hydraulic fracturing, SAGD, CSS and waterflooding programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as hydraulic fracturing, SAGD, CSS and waterflooding. If the Company is unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CSS or waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

The anticipated benefits of acquisitions may not be achieved and the Company may dispose of assets for less than their carrying value on the financial statements

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production and the success of any acquisition will depend on several factors and involves potential risks and uncertainties. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Additionally, significant acquisitions can change the nature of our operations and business if acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Even though we assess and review the properties we seek to acquire in a manner consistent with what we believe to be industry practice, such reviews are limited in scope, inexact and not capable of identifying all existing or potentially adverse conditions. As a result, the anticipated and desired benefits of an acquisition may not materialize, and may have a material and adverse effect on our business, financial performance and results of operations.

Management continually assesses the value and contribution of its Company's assets. In this regard, certain assets may be periodically disposed of so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such assets, certain assets of the Company, if disposed of, may realize less on disposition than their carrying value on the financial statements of the Company.

Variations in foreign exchange rates could adversely affect our financial condition

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our production revenues. Future Canadian/U.S. exchange rates could accordingly impact the future value of Baytex's reserves as determined by independent reserves evaluators. Although a low value of the Canadian dollar relative to the U.S. dollar may positively impact the price the Company receives for crude oil and natural gas production it could also result in an increase in the price of certain goods used in operations which may have a negative impact on the Company's financial results.

Availability and cost of capital or borrowing to maintain and/or fund future development and acquisitions

The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital (including, but not limited to, debt and equity financing) become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to investors, or should our business prospects deteriorate, our ability to access additional capital could decrease. Additionally, from time to time, our securities may not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. This may include changes to market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors. These events would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing, and may increase our borrowing costs.

From time to time, we may enter into transactions which may be financed in whole or in part with debt or equity. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

The reserves estimates included in the AIF for the year ended December 31, 2025 are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2025 are estimated using forecast prices and costs as set forth under *"Statement of Reserves Data - Pricing Assumptions"* in the AIF for the year ended December 31, 2025. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Reserve reports based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

Restrictions and/or costs associated with regulatory initiatives to combat climate change and the physical risks of climate change may have a material adverse affect on our business

Regulatory and Policy Initiatives

Our exploration and production facilities and other operational activities emit GHGs. As such, GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs, additional taxes, increased construction and development costs, additional monitoring and compliance costs, a requirement to redesign or retrofit current facilities, permitting delays, additional costs associated with the purchase of emission credits or allowances, the availability to use necessary third-party services and facilities that we rely on, and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our financial condition, results of operations or prospects.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation and Litigation*" in the AIF for the year ended December 31, 2025.

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes, drought and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes, drought and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

An energy transition that lessens demand for petroleum products may have an adverse affect on our business

A transition away from the use of petroleum products, which may include conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy, could reduce demand for oil and natural gas. Certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

Failure to retain or replace our leadership and key personnel may have an adverse affect on our business

Our success is dependent upon our management, our leadership capabilities and the quality and competency of our talent. Contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. In addition, certain of the Company's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and prospects.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects our financial condition, results of operations and prospects.

In addition, tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details, see "Legal Proceedings and Regulatory Actions" in the AIF for the year ended December 31, 2025. Any such reassessment may have an impact on current and future taxes payable. We believe appropriate provisions for current and deferred income taxes have been made in our consolidated financial statements; however, it is difficult to predict the outcome of audit findings by tax authorities or their final adjudication by the courts. These findings may increase the amount of our tax liabilities and adversely affect our business, financial condition and results of operations.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business, community relationships and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the frequency of operational shut-ins and unintentional communication with other adjacent wells and reduce the total recoverable reserves from the reservoir.

Our financial performance is significantly affected by the cost of developing and operating our assets

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation, increased costs due to tariffs, access to skilled and unskilled labour, availability of equipment, scheduling delays, trucking and fuel costs, failure to maintain quality construction standards, the cost of new technologies and supply chain disruptions. Labour costs, natural gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

Our information technology systems are subject to certain risks

We utilize and have become increasingly dependent upon a number of information technology systems for the administration and management of our business and are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although the Company has security measures and controls in line with industry-accepted standards in place to mitigate these risks, a breach of its security measures disruption of critical information technology services, and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws, and/or disruption to business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition, results of operations or our reputation, and any damages may not be adequately covered by the Company's current insurance coverage. In addition, our vendors, suppliers and other businesses partners may separately suffer disruptions as a result of such security breaks which may directly or indirectly affect our business activities.

The Company's IT systems may incorporate artificial intelligence ("AI"), and development of these capabilities is ongoing. AI introduces risks and unintended consequences that could affect adoption and business operations. Algorithms and training methods may be flawed, and reliance on AI without adequate safeguards can lead to inaccurate outcomes or operational vulnerabilities.

AI also poses data privacy, cyber-security, and intellectual property risks. Improper use may result in unauthorized disclosure of sensitive information or outputs that infringe copyrights, patents, or privacy rights. As legal and regulatory frameworks for AI remain uncertain, future compliance obligations could impose significant costs or limit the Company's ability to integrate AI tools.

Adverse results from litigation may have an adverse affect on our business and reputation

In the normal course of our operations, we currently are and from time to time in the future may become involved in, be named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. In addition, we retained liability for certain legal proceedings related to our prior ownership of assets located in the U.S. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, and environmental issues, including claims relating to contamination or natural resource damages and contract disputes.

The Company establishes legal provisions for known and potential claims for which payment is probable and can be reliably estimated. The Company also has comprehensive liability insurance coverage; however such insurance does not cover all risks to which we might be exposed and in other cases, may only partially cover losses incurred by the Company. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Furthermore, even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition. For further details, see "*Legal Proceedings and Regulatory Actions*" in the AIF for the year ended December 31, 2025.

Current or future controls, legislation or regulations applicable to the oil and gas industry could adversely affect us

Operations

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, completion operations, including the use of hydraulic fracturing, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions*" in the AIF for the year ended December 31, 2025.

Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal, state, and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions*" in the AIF for the year ended December 31, 2025.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company may have to pay certain costs associated with abandonment and reclamation

The Company will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Company's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial. The Company records a provision for abandonment and reclamation costs in its consolidated financial statements, this provision requires significant judgment and reflects the Company's best estimate of the costs to complete the required abandonment and reclamation work. Actual results may be significantly different than the estimated amounts.

Foreign Investment and Competition Act Legislation

In addition to regulatory requirements mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

New regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Hydraulic fracturing has featured prominently in recent political, media and activist commentary on the subject of water usage, induced seismicity events and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing, or could effectively prevent the development of crude oil and natural gas. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Regulations regarding the disposal of fluids used in the Company's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal, provincial and state governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

Acquiring, developing and exploring for oil and natural gas involves many physical hazards. We have not insured and cannot fully insure against all risks related to our operations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to the: (i) storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; including horizontal multi-well pad developments; and (iii) operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, fires, explosions, equipment failures and other accidents, gaseous leaks, uncontrollable or unauthorized flows of crude oil, natural gas or well fluids, migration of harmful substances, oil spills, corrosion, adverse weather conditions, pollution, acts of vandalism, theft and terrorism and other adverse risks to the environment.

If any of the foregoing risks were to materialize, we could sustain material losses as a result of injury or loss of life, damage to, or destruction of, property, natural resources or equipment, including the costs of repair or replacement, pollution or other environmental harm, interruptions to our ongoing operations, including the reduction or shutting-in of existing production, regulatory investigations and administrative, civil and criminal penalties, and limitation or suspension of current or future operations.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

Our thermal heavy oil projects face additional risks compared to conventional oil and gas production

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on CSS, SAGD or other new technologies to become uneconomic, which could have an adverse effect on our financial condition and our reserves. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Project economics and our earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: the costs imposed by GHG emissions regulations, labour costs, the cost of catalysts and chemicals, the cost of natural gas and electricity, water handling and availability, power outages, produced sand causing issues of erosion, hot spots and corrosion, reliability of facilities, maintenance costs, the cost to transport sales products and the cost to dispose of certain by-products.

We may be unable to compete successfully with other organizations in the oil and natural gas industry, or obtain required vendor services to compete

The oil and natural gas industry is highly competitive in all of its phases. The Company competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas, as well as for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as drilling rigs, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than the Company. As a result, such competition can significantly increase costs and some of the Company's competitors may have greater opportunities and be able to access, services or vendors that the Company is not able to access, thereby limiting its ability to compete.

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity could adversely affect our financial condition

Our Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms, if at all. There can be no assurance that the amount of our Credit Facilities will be adequate for our future financial obligations, including future capital expenditures, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund ongoing operations. In the event that the Credit Facilities are not extended prior to maturity, indebtedness under the Credit Facilities will be repayable at that time. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms. See "*Description of Capital Structure*" in the AIF for the year ended December 31, 2025.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in the Provinces of Alberta and Saskatchewan. In the future, we may acquire or move into new industry related activities or new geographical areas and may acquire different energy-related assets. As a result, we may face unexpected risks or, alternatively, our exposure to one or more existing risk factors may be significantly increased, which may in turn result in our future operational and financial conditions being adversely affected.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, and legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on our business and financial results.

Public perception and its influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, rail car derailments, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flow from operating activities and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity and increase our costs.

Geopolitical risk and conflicts in or around major oil and gas producing nations can significantly impact commodity prices and, therefore the financial condition of the oil and gas industry

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The short-, medium- and long-term implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflict(s), it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; change in trade relations and policies, including the potential for tariffs; and supply chains and cost-effective and timely transportation.

Our hedging activities may negatively impact our income and our financial condition

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and for certain assets will result in us paying royalties at a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, which may adversely impact our revenues in future periods. For more information about our commodity hedging program, see *"Description of our Business - Marketing Arrangements and Forward Contracts"* in the AIF for the year ended December 31, 2025.

Failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the 2032 Notes. If we fail to comply with such covenants, are unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our Shareholders.

Conflicts of interest may arise between the Company and its directors and officers

Circumstances may arise where directors and officers of the Company are directors or officers of other companies involved in the oil and gas industry which are in competition to, or otherwise in conflict with, the interests of the Company. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Company. Where employee conflicts exist, they are to be provided in writing to our Human Resources Department, which discloses all conflicts to Chief Legal Officer. See "*Directors and Officers – Conflicts*" in the AIF for the year ended December 31, 2025 and the Company's Code of Business Conduct and Ethics at *www.baytexenergy.com.*

Risks Related to Ownership of our Securities

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates, the decision of certain indices to include our Common Shares and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Forward-Looking Information rely upon assumptions which may not prove correct

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Special Notes to Reader – Forward-Looking Statements*" in the AIF for the year ended December 31, 2025.

Dividends on the Company's Common Shares and Common Share repurchases are variable

The future acquisition by the Company of Common Shares pursuant to a share buyback (including through its NCIB) and the payment of dividends, if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback or to pay dividends will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, commodity prices, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on the Company under applicable corporate law. In the future, there can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback and there can be no assurance that dividends will be paid or, if paid the amount of such dividends.

The Company could lose its status as a "foreign private issuer" in the United States

The Company is required to assess its "foreign private issuer" ("FPI") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Company currently qualifies as an FPI, it could lose its FPI status in the future. If the Company were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Company loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Company under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Company incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Company would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Company as a foreign private issuer. The Company would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Company's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Company may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent qualified reserves evaluators), and all or a substantial portion of their assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserves quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We have included in the AIF for the year ended December 31, 2025 estimates of proved reserves and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in the AIF for the year ended December 31, 2025 may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes in the AIF for the year ended December 31, 2025 may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by us to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2025, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2025 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2025.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of the Company. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

/s/ Eric T. Greager

Eric T. Greager
Chief Executive Officer
Baytex Energy Corp.

/s/ Chad L. Kalmakoff

Chad L. Kalmakoff
Chief Financial Officer
Baytex Energy Corp.

March 4, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (the Company) as of December 31, 2025 and 2024, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements 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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), 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, and our report dated March 4, 2026 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the 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 audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits 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. We believe that our audits provide a reasonable basis for our opinion.

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: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) 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.

Assessment of the recoverable amount of oil and gas properties

As discussed in note 6 to the consolidated financial statements, the Company identified indicators of impairment and indicators of impairment reversal as of December 31, 2025 related to the Company's Viking and Lloydminster cash generating units ("CGUs"), respectively. The Company therefore determined the recoverable amount as of December 31, 2025 of each of the CGUs and recorded an impairment of $148.0 million in the carrying amount of the Viking CGU. The determination of recoverable amount of a CGU involves numerous estimates, including cash flows associated with estimated proved plus probable oil and gas reserves of the CGU ("CGU reserves cash flows") and the discount rate. The estimation of CGU reserves cash flows in the reserve report involves the expertise of independent qualified reserve evaluators, who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "CGU reserve report assumptions"). The Company engages independent qualified reserve evaluators to estimate CGU reserves cash flows.

We identified the assessment of the recoverable amount of the Viking and Lloydminster CGUs as a critical audit matter. Changes in CGU reserve report assumptions and discount rates could have had a significant impact on the estimate of recoverable amounts and the resulting impairment or impairment reversal in the carrying amount of oil and gas properties relating to the CGUs. A high degree of auditor judgment was required to evaluate the Company's estimates of CGU reserves cash flows, and related CGU reserve report assumptions, and the discount rates, which were inputs into the calculation of recoverable amounts. Additionally, the evaluation of these recoverable amounts required the involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's determination of the recoverable amount of each of the CGUs, including the discount rate
- the Company's determination of the CGU reserve report assumptions and resulting CGU reserves cash flows.

We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company, who estimated the CGU reserves cash flows. We evaluated the methodology used by the independent qualified reserves evaluators to estimate the CGU reserves cash flows for compliance with the applicable regulatory standards. We compared the current year actual CGU production volumes, royalty obligations, operating and capital costs to those estimates used in the prior year estimate of proved reserves by CGU to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the CGU reserves cash flows by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the current year estimate of the CGU reserves cash flows by comparing them to historical results.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of discount rates by comparing the inputs of the discount rates against publicly available market data for comparable assets and assessing the resulting discount rates
- evaluating the Company's estimate of recoverable amount of the CGUs by comparing to publicly available market data and valuation metrics for comparable entities.

Impact of estimated oil and gas reserves on depletion expense related to continuing operations

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved plus probable oil and gas reserves by depletable area ("area reserves"). As discussed in note 6 to the consolidated financial statements, the Company recorded depletion expense related to continuing operations of $480.0 million for the year ended December 31, 2025. The estimation of area reserves involves the expertise of independent qualified reserve evaluators who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "area reserve report assumptions"). The Company engages independent qualified reserve evaluators to estimate area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to continuing operations as a critical audit matter. Changes in area reserve report assumptions could have had a significant impact on the calculation of depletion expense of the depletable area. A high degree of auditor judgment was required in evaluating the area reserves, and related area reserve report assumptions, which were used in the calculation of depletion expense.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's calculation of depletion expense by depletable area
- the Company's determination of area reserve report assumptions and resulting area reserves.

We assessed the calculation of depletion expense for compliance with International Financial Reporting Standards as issued by the International Accounting Standards Board. We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company. We evaluated the methodology used by the independent qualified reserve evaluators to estimate area reserves for compliance with the applicable regulatory standards. We compared the current year actual production volumes, royalty obligations, operating and capital costs to those estimates used in the prior year estimate of proved reserves for a selection of CGUs to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of area reserves by comparing them to those published by other reserves engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the estimate of area reserves for a selection of CGUs by comparing them to historical results.

<u>/s/ KPMG LLP</u>

Chartered Professional Accountants

We have served as the Company's auditor since 2016.

Calgary, Canada
March 4, 2026

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (the Company) 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. 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 Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2025 and 2024, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements), and our report dated March 4, 2026 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible 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 Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. 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 audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) 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 (3) 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.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 4, 2026

Baytex Energy Corp.
Consolidated Statements of Financial Position
(thousands of Canadian dollars)

As at	Notes	December 31, 2025	December 31, 2024
ASSETS			
Current assets			
Cash	19	**$ 953,113**	$ 16,610
Trade receivables	15, 19	**135,230**	387,266
Prepaids and other assets		**35,008**	20,178
Financial derivatives	19	**28,898**	25,573
Assets held for sale	4	**38,117**	—
		1,190,366	449,627
Non-current assets			
Exploration and evaluation assets	5	**133,585**	124,355
Oil and gas properties	6	**1,918,435**	6,921,168
Other plant and equipment		**7,648**	8,025
Lease assets	8	**20,812**	22,068
Prepaids and other assets	16	**28,224**	56,290
Deferred income tax asset	16	**46,344**	178,212
		$ 3,345,414	$ 7,759,745
LIABILITIES			
Current liabilities			
Trade payables	19	**$ 236,373**	$ 512,473
Share-based compensation liability	13	**26,108**	18,806
Dividends payable	12,19	**17,268**	17,598
Financial derivatives	19	**2,406**	—
Liabilities related to asset held for sale	4	**23,710**	—
Lease obligations	8	**7,175**	9,193
Asset retirement obligations	11	**17,138**	15,656
		330,178	573,726
Non-current liabilities			
Other long-term liabilities		**—**	20,887
Share-based compensation liability	13	**8,694**	5,926
Financial derivatives	19	**—**	1,645
Credit facilities	9	**1,138**	324,346
Long-term notes	10	**93,834**	1,932,890
Lease obligations	8	**15,844**	15,459
Asset retirement obligations	11	**506,677**	625,295
Deferred income tax liability	16	**—**	88,561
		956,365	3,588,735
SHAREHOLDERS' EQUITY			
Shareholders' capital	12	**6,072,562**	6,137,479
Contributed surplus		**397,681**	361,854
Accumulated other comprehensive income		**13,356**	1,093,261
Deficit		**(4,094,550)**	(3,421,584)
		2,389,049	4,171,010
		$ 3,345,414	$ 7,759,745

Subsequent events (notes 4 and 12) and Commitments and Contingencies (note 21)
See accompanying notes to the consolidated financial statements.

/s/ Jennifer A. Maki
Jennifer A. Maki
Director, Baytex Energy Corp.

/s/ Don G. Hrap
Don G. Hrap
Director, Baytex Energy Corp.

Baytex Energy Corp.
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(thousands of Canadian dollars, except per common share amounts and weighted average common shares)

Years Ended December 31	Notes	2025	2024 Revised (1)
Revenue, net of royalties			
Petroleum and natural gas sales	15	**$ 1,684,648**	$ 1,874,046
Royalties		**(203,833)**	(261,205)
		1,480,815	1,612,841
Expenses			
Operating		**334,317**	336,069
Transportation		**83,697**	84,211
Blending and other		**234,990**	263,943
General and administrative		**67,903**	58,363
Transaction costs		**—**	1,539
Exploration and evaluation	5	**5,534**	779
Depletion and depreciation		**484,932**	483,314
Impairment	6	**148,000**	—
Share-based compensation	13	**24,041**	11,871
Financing and interest	17	**322,017**	244,951
Financial derivatives loss (gain)	19	**17,071**	(2,101)
Foreign exchange (gain) loss	18	**(94,019)**	155,895
Gain on dispositions		**(2,528)**	(4,134)
Other expense (income)		**7,970**	(5,141)
		1,633,925	1,629,559
Net loss before income taxes from continuing operations		**(153,110)**	(16,718)
Income taxes	16		
Current income tax expense		**9,721**	17,821
Deferred income tax expense		**114,014**	62,914
		123,735	80,735
Net loss from continuing operations		**$ (276,845)**	$ (97,453)
Net (loss) income from discontinued operations	7	**$ (326,934)**	$ 334,050
Net (loss) income		**$ (603,779)**	$ 236,597
Other comprehensive (loss) income			
Foreign currency translation adjustment		**(213,231)**	402,344
Reclassification of cumulative foreign currency translation of discontinued foreign operations	7	**(866,674)**	—
Comprehensive (loss) income		**$ (1,683,684)**	$ 638,941
Net (loss) income per common share			
Continuing operations - basic		**$ (0.36)**	$ (0.12)
Discontinued operations - basic		**$ (0.43)**	$ 0.41
Net (loss) income per share - basic		**$ (0.78)**	$ 0.29
Continuing operations - diluted		**$ (0.36)**	$ (0.12)
Discontinued operations - diluted		**$ (0.43)**	$ 0.41
Net (loss) income per share - diluted		**$ (0.78)**	$ 0.29
Weighted average common shares	14		
Basic		**769,180**	803,435
Diluted		**769,180**	807,711

(1) Comparative period has been revised to reflect current period presentation. See Note 7 for additional information.

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Changes in Equity
(thousands of Canadian dollars)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**
Vesting of share awards	12	1,167	—	—	—	**1,167**
Repurchase of common shares for cancellation	12	(390,977)	168,777	—	—	**(222,200)**
Dividends declared	12	—	—	—	(71,985)	**(71,985)**
Comprehensive income		—	—	402,344	236,597	**638,941**
Balance at December 31, 2024		$ 6,137,479	$ 361,854	$ 1,093,261	$ (3,421,584)	**$ 4,171,010**
Vesting of share awards	12	330	—	—	—	**330**
Repurchase of common shares for cancellation	12	(65,247)	35,827	—	—	**(29,420)**
Dividends declared	12	—	—	—	(69,187)	**(69,187)**
Comprehensive loss		—	—	(213,231)	(603,779)	**(817,010)**
Reclassification of cumulative foreign currency translation of discontinued foreign operations	7	—	—	(866,674)	—	**(866,674)**
Balance at December 31, 2025		$ 6,072,562	$ 397,681	$ 13,356	$ (4,094,550)	**$ 2,389,049**

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

Years Ended December 31	Notes	2025	2024
CASH PROVIDED BY (USED IN):			
Operating activities			
Net (loss) income		**$ (603,779)**	$ 236,597
Adjustments for:			
Unrealized foreign exchange (gain) loss	18	**(88,538)**	153,930
Exploration and evaluation	5	**5,534**	779
Depletion and depreciation		**1,264,692**	1,385,910
Impairment	6	**148,000**	—
Non-cash financing and accretion	17	**170,886**	62,270
Unrealized financial derivatives gain	19	**(2,564)**	(654)
Loss on dispositions		**508,080**	1,220
Costs of disposal	7	**(26,383)**	—
Deferred income tax expense	16	**112,241**	114,927
Asset retirement obligations settled	11	**(20,318)**	(28,793)
Change in non-cash working capital	20	**18,111**	(17,922)
Cash flows from operating activities		**1,485,962**	1,908,264
Financing activities			
Decrease in credit facilities	9	**(334,253)**	(539,676)
Debt issuance costs		**(2,997)**	(25,023)
Payments on lease obligations	8	**(13,272)**	(15,510)
Net proceeds from issuance of long-term notes	10	**—**	780,936
Redemption of long-term notes	10	**(1,879,806)**	(580,913)
Repurchase of common shares	12	**(29,420)**	(222,200)
Dividends declared	12	**(69,187)**	(71,985)
Change in non-cash working capital	20	**(1,620)**	6,200
Cash flows used in financing activities		**(2,330,555)**	(668,171)
Investing activities			
Additions to exploration and evaluation assets	5	**(930)**	—
Additions to oil and gas properties	6	**(1,205,141)**	(1,256,633)
Additions to other plant and equipment		**(2,281)**	(5,370)
Additions to assets held for sale	4	**(38,117)**	—
Advances received for assets held for sale	4	**23,334**	—
Property acquisitions		**(32,018)**	(52,415)
Proceeds from dispositions, net of cash disposed		**3,018,427**	46,495
Change in non-cash working capital	20	**17,822**	(11,375)
Cash flows from (used in) investing activities		**1,781,096**	(1,279,298)
Change in cash		**936,503**	(39,205)
Cash, beginning of year		**16,610**	55,815
Cash, end of year		**$ 953,113**	$ 16,610
Supplementary information			
Interest paid		**$ 202,494**	$ 200,218
Income taxes paid		**$ 22,094**	$ 19,430

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. The Company’s common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PREPARATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The material accounting policies set forth below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 4, 2026.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the material accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

The Company's Canadian operations are presented herein as continuing operations and its U.S. operations have been classified and presented as discontinued operations. A segment note is no longer presented as there is only one operating segment remaining at period end. See Note 7 - "Discontinued Operations" for additional information.

Measurement Uncertainty and Judgments

Management makes judgments and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids ("NGL") reserves, the recoverable amount of long-lived assets or cash-generating units ("CGUs"), the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and NGL reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the estimation of recoverable amount for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by an independent qualified reserves evaluator and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the estimation of recoverable amount estimates for non-financial assets.

Cash-generating Units

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment or Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. These indicators can be internal such as changes in estimated proved plus probable oil and gas reserves and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

Measurement of Recoverable Amounts

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim wells and facilities, the estimated time period during which these costs will be incurred in the future, and risk-free discount rates and inflation rates derived from observable market data. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. The timing of asset retirement obligation expenditures may occur earlier than estimated. The timing of asset retirement obligations is supported by externally evaluated reserves with consideration by the Company of regulatory requirements.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the applicable legislative requirements may result in a material change to the Company's provision for income taxes.

Environmental Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released voluntary standards for reporting periods starting on or after January 1, 2025 that are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators ("CSA") have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. In April 2025, the CSA announced it is pausing development of new sustainability reporting requirements to allow issuers to adapt to recent developments in the U.S. and globally. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

3. MATERIAL ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Intercompany transactions are eliminated in preparation of the consolidated financial statements.

Many of the Company's exploration, development and production activities are conducted through jointly owned assets. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by jointly owned assets.

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, NGL, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product and it is physically transferred to the customer at the agreed upon delivery point.

Contracts are evaluated based on the nature of the performance obligations, including the Company's role as either principal or agent. Where the Company acts as principal and has primary responsibility for the transaction, revenue is recognized on a gross basis. Where the Company acts as agent, revenue is recognized on a net basis.

The transaction price for variable price contracts is based on a representative commodity price index, and typically includes adjustments for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded varies depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Pipeline tariffs, tolls and fees charged to other entities for the use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Pipeline tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Exploration and Evaluation ("E&E") Assets

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as E&E assets until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E expenditures are costs incurred in an area where technical feasibility and commercial viability has not yet been determined. The technical feasibility and commercial viability is dependent on whether extracting petroleum and natural gas resources is demonstrable. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E assets associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by demonstrating the ability to extract mineral resources and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Oil and gas properties are initially recorded at cost and include the costs to acquire, develop, complete geological and geophysical surveys, drill and complete wells for production, and construct and install infrastructure including wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the economic benefits of the replacement will be realized by the Company in the future. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Depletion

The costs associated with oil and gas properties are depleted on a unit-of-production basis by depletable area over proved plus probable reserves once commercial production has commenced. Forecasted capital costs required to bring proved plus probable reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

Impairment or Impairment Reversal

Non-financial Assets

The Company reviews its oil and gas properties and E&E assets at a CGU level for indicators of impairment or impairment reversal at the end of each reporting period. E&E assets are also assessed for impairment upon transfer to oil and gas properties. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist.

When reviewing for indicators of impairment or impairment reversal, and testing for impairment or impairment reversal when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. The determination of recoverable amount includes estimates of proved plus probable oil and gas reserves and the associated cash flows. Factors that impact these cash flows include forecasted CGU production volumes, royalty obligations, operating costs, capital costs, commodity prices, taxes, along with inflation and discount rates used to estimate present value. FVLCD is the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction. In determining FVLCD, recent comparable market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a discount rate based on the Company’s weighted average cost of capital adjusted for risks specific to the CGU.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the CGU’s revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with similar characteristics. The lease asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs, on commencement of the lease. Depreciation is recognized on the lease asset over the shorter of the estimated useful life of the asset or the lease term.

Lease payments are allocated between the liability and interest expense. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The Company’s asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and facilities using existing technology and the estimated time period during which these costs will be incurred in the future.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, discounted using the risk-free rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within financing and interest expense in net income or loss. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign Transactions

Transactions in foreign currencies are translated to Canadian dollars at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to Canadian dollars at the period-end exchange rate and revenue and expenses are translated to Canadian dollars using the average exchange rate for the period. Realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income or loss.

Foreign Operations

The Company had U.S operations owned via U.S. subsidiaries. The assets and liabilities of foreign operations are translated to Canadian dollars at exchange rates in effect at the period-end exchange rate. Revenue and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are included in other comprehensive income or loss. The cumulative foreign currency translation differences are reclassified from shareholders' equity to net income or loss upon discontinuation of the foreign operations.

Financial Instruments

Financial assets are initially classified into two categories: measured at amortized cost or fair value through profit or loss ("FVTPL").

The measurement category for each class of financial asset and financial liability is set forth in the following table.

Financial Instrument	Classification
Cash	Amortized cost
Trade receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade payables	Amortized cost
Dividends payable	Amortized cost
Credit facilities	Amortized cost
Long-term notes	Amortized cost

Debt issuance costs related to the amendment of the Company's credit facilities or the issuance of long-term notes are capitalized and amortized as financing costs over the term of the credit facilities or long-term notes. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income or loss over the term of the financial instrument. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed at inception of the contract.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income or loss when incurred.

The Company accounts for its physical delivery sales contracts as executory contracts. These contracts are entered into and held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments and are not recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Income Taxes

Current and deferred income taxes are recognized in net income or loss, except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period. The Company recognizes the financial statement impact of a tax filing position when it is probable that the position will be upheld. The asset or liability is measured based on an assessment of probable outcomes and their associated probabilities.

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all deductible temporary differences to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced or increased to the extent that it is no longer probable or becomes probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes.

Assets Held for Sale

Assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a sale rather than through future operating cash flows. This conditions is met when the sale is highly probable and the asset is available for immediate sale in its present condition. Immediately before the assets are classified as held for sale, they are assessed for indicators of impairment or reversal of impairment and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges are recognized in net income or loss. Assets held for sale and their associated liabilities are classified as current assets and any liabilities associated with assets held for sale are classified as current liabilities.

Future Accounting Pronouncements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued in April 2024 and replaces IAS 1 *Presentation of Financial Statements*. The Standard introduces a more defined structure to the statements of income or loss and comprehensive income or loss, including new categories of income and expenses, defined subtotals, and required disclosure of management-defined performance measures. The Standard is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* were amended in May 2024 to clarify the date of recognition and derecognition of financial assets and liabilities. The amendments are effective for fiscal years beginning on or after January 1, 2026, and the Company has determined that the impact from this amendment is immaterial.

4. ASSETS HELD FOR SALE

In March 2025, Gibson Energy Inc. ("Gibson") and Baytex entered into a 15-year take-or-pay agreement under which Baytex constructed certain oil and gas infrastructure funded by Gibson over the period of construction. As at December 31, 2025, construction was complete, with $38.1 million of construction costs incurred, $23.3 million of advances received from Gibson and $0.4 million of construction payables outstanding. The oil and gas infrastructure assets were classified as assets held for sale at December 31, 2025 at their carrying value, which is equivalent to the fair value less costs to sell.

In February 2026, ownership transferred to Gibson upon completion and acceptance in accordance with the Construction and Conveyance Agreement. No gain or loss was recognized on transfer as the assets were sold at cost.

5. EXPLORATION AND EVALUATION ASSETS

	December 31, 2025	December 31, 2024
Balance, beginning of year	**$ 124,355**	$ 90,919
Capital expenditures	**930**	—
Property acquisitions	**34,148**	39,355
Divestitures	**(8,577)**	(2,009)
Exploration and evaluation expense	**(5,534)**	(779)
Transfers to oil and gas properties (note 6)	**(11,737)**	(3,131)
Balance, end of year	**$ 133,585**	$ 124,355

At December 31, 2024 and 2025, the Company assessed its exploration and evaluation assets for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of its CGUs.

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2023	**$ 15,526,017**	**$ (8,906,984)**	**$ 6,619,033**
Capital expenditures	1,256,633	—	1,256,633
Property acquisitions	16,437	—	16,437
Transfers from exploration and evaluation assets (note 5)	3,131	—	3,131
Transfers from lease assets (note 8)	8,210	—	8,210
Change in asset retirement obligations (note 11)	25,253	—	25,253
Divestitures	(187,103)	135,742	(51,361)
Foreign currency translation	794,766	(378,871)	415,895
Depletion	—	(1,372,063)	(1,372,063)
Balance, December 31, 2024	**$ 17,443,344**	**$ (10,522,176)**	**$ 6,921,168**
Capital expenditures	1,205,141	—	1,205,141
Property acquisitions	2,147	—	2,147
Transfers from exploration and evaluation assets (note 5)	11,737	—	11,737
Change in asset retirement obligations (note 11)	(11,311)	—	(11,311)
Divestitures (note 7)	(10,838,470)	6,250,607	(4,587,863)
Impairment loss	—	(148,000)	(148,000)
Foreign currency translation	(450,006)	230,586	(219,420)
Depletion (1)	—	(1,255,164)	(1,255,164)
Balance, December 31, 2025	**$ 7,362,582**	**$ (5,444,147)**	**$ 1,918,435**

(1) Inclusive of depletion expense related to continuing operations of $480.0 million (2024 - $473.8 million) and discontinued operations $775.1 million (2024 - $898.3 million).

At December 31, 2025, the Company assessed its oil and gas properties for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for three of five CGUs. The Company identified indicators of impairment for oil and gas properties in its Viking CGU due to negative technical revisions in proved plus probable reserves. The recoverable amount for the Viking CGU was not sufficient to support its carrying value which resulted in an impairment of $148.0 million recorded at December 31, 2025. The Company identified indicators of impairment reversal for oil and gas properties in its Lloydminster CGU due to a decrease in the asset-specific discount rate. The recoverable amount for the Lloydminster CGU supports its carrying value and no impairment reversal was recorded at December 31, 2025. The recoverable amount is based on a fair value less costs of disposal model using estimated cash flows associated with proved plus probable reserves from an independent reserve report prepared as at December 31, 2025 utilizing a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 14%.

At December 31, 2025, the recoverable amount of the Viking and Lloydminster CGUs were calculated using the following benchmark reference prices for the years 2026 to 2035 adjusted for commodity differentials specific to the CGUs. The prices and costs subsequent to 2035 have been adjusted for inflation at an annual rate of 2.0%.

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
WTI crude oil (US$/bbl)	59.92	65.10	70.28	71.93	73.37	74.84	76.34	77.87	79.42	81.01
WCS heavy oil ($/bbl)	65.13	70.43	76.90	78.71	80.29	81.90	83.53	85.20	86.91	88.65
Edmonton par oil ($/bbl)	77.54	83.60	90.17	92.32	94.17	96.06	97.98	99.93	101.93	103.97
AECO gas ($/mmbtu)	3.00	3.30	3.49	3.58	3.65	3.72	3.80	3.88	3.95	4.03

The following table demonstrates the sensitivity of the estimated recoverable amount of the Lloydminster and Viking CGUs to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment loss (reversal)	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Lloydminster CGU	$ 327,216	$ —	$ 27,250	$ 82,500	$ 500
Viking CGU	407,201	148,000	19,000	45,500	3,500

At December 31, 2024, the Company assessed its oil and gas properties for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of its CGUs.

7. DISCONTINUED OPERATIONS

On December 19, 2025, the Company completed the disposition of the operated and non-operated assets in its Eagle Ford CGUs. The Eagle Ford CGUs represent a geographical area of the Company's operations, therefore, its results have been classified as discontinued operations in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*. Upon disposition of the Company's U.S. operations, the cumulative foreign currency translation recognized in accumulated other comprehensive income of $866.7 million was reclassified from shareholders' equity to net income or loss.

The following table summarizes the Company's financial results from discontinued operations:

Years Ended December 31		**2025**		2024
Revenue, net of royalties				
Petroleum and natural gas sales	**$**	**1,888,524**	$	2,334,909
Royalties		**(508,305)**		(618,881)
		1,380,219		1,716,028
Expenses				
Operating		**292,424**		317,880
Transportation		**45,683**		48,931
General and administrative		**35,622**		23,383
Depletion and depreciation		**779,760**		902,596
Share-based compensation		**9,268**		6,001
Financing and interest		**22,985**		23,423
Foreign exchange gain		**(3,624)**		—
Loss on dispositions		**—**		5,354
Other income		**(4,061)**		(1,548)
		1,178,057		1,326,020
Net income before income taxes - operations		**202,162**		390,008
Income taxes - operations				
Current income tax (recovery) expense - operations		**(8,485)**		3,945
Deferred income tax (recovery) expense - operations		**(1,773)**		52,013
		(10,258)		55,958
Net income - operations	**$**	**212,420**	$	334,050
Loss on disposition after tax		**(539,354)**		
Net (loss) income - discontinued operations	**$**	**(326,934)**	$	334,050

		USD		CAD (1)
Consideration				
Total cash consideration received	$	2,188,322	$	3,011,897
Costs to sell		(19,169)		(26,383)
Net consideration received	**$**	**2,169,153**	**$**	**2,985,514**
Net assets disposed				
Oil and gas properties	$	(3,320,890)	$	(4,570,708)
Cash		(3,543)		(4,876)
Working capital (2)		35,817		49,299
Lease assets		(6,372)		(8,771)
Lease obligations		6,983		9,611
Asset retirement obligations		65,698		90,424
Deferred income tax liability		52,476		72,225
Carrying value of net assets disposed	**$**	**(3,169,831)**	**$**	**(4,362,796)**
Loss on disposition before reclassification of foreign currency translation		(1,000,678)		(1,377,282)
Current income tax expense - disposition		(20,758)		(28,746)
Reclassification of cumulative foreign currency translation of discontinued foreign operations		—		866,674
Loss on disposition after tax	**$**	**(1,021,436)**	**$**	**(539,354)**

(1) Exchange rate used to translate the U.S. denominated values above is the rate as at the closing date being CAD/USD 1.37635.
(2) Working capital includes $193.8 million (US$140.8 million) of trade receivables, $4.7 million (US$3.4 million) of prepaids and other assets, and $247.8 million (US$180.1 million) of trade payables and share-based compensation liability.

The following table summarizes cash flows from discontinued operations reported in the consolidated statements of cash flows:

Years Ended December 31		**2025**		2024
Cash provided by (used in) discontinued operations:				
Operating activities	**$**	**940,645**	$	1,280,427
Financing activities		**(207,371)**		(85,592)
Investing activities		**2,371,215**		(787,098)
Increase in cash from discontinued operations	**$**	**3,104,489**	$	407,737

8. LEASES

Lease Assets

Baytex had the following right-of-use assets:

	Office Leases	Field Equipment	Vehicles and Other	Total
Balance, December 31, 2023	**$ 15,226**	**$ 12,029**	**$ 890**	**$ 28,145**
Additions	157	7,290	423	7,870
Modifications	—	1,752	267	2,019
Depreciation	(2,650)	(5,093)	(850)	(8,593)
Transfers to oil and gas properties (note 6)	—	(8,210)	—	(8,210)
Foreign currency translation	358	475	4	837
Balance, December 31, 2024	**$ 13,091**	**$ 8,243**	**$ 734**	**$ 22,068**
Additions	106	17,918	1,052	19,076
Dispositions	(2,896)	(5,865)	(8)	(8,769)
Modifications	(1,904)	4,579	(68)	2,607
Depreciation	(2,393)	(10,642)	(760)	(13,795)
Foreign currency translation	(159)	(216)	—	(375)
Balance, December 31, 2025	**$ 5,845**	**$ 14,017**	**$ 950**	**$ 20,812**

Lease Obligations

Baytex had the following future commitments associated with its lease obligations:

	December 31, 2025	December 31, 2024
Less than 1 year	**$ 8,487**	$ 10,788
1 - 3 years	**10,690**	9,175
3 - 5 years	**7,097**	7,200
After 5 years	**—**	1,928
Total lease payments	**$ 26,274**	$ 29,091
Amounts representing interest over the term of the lease	**(3,255)**	(4,439)
Present value of net lease payments	**$ 23,019**	$ 24,652
Less current portion of lease obligations	**7,175**	9,193
Non-current portion of lease obligations	**$ 15,844**	$ 15,459

The Company recorded interest expense related to its lease obligations of $1.3 million and recorded lease payments, excluding interest, of $13.3 million for the year ended December 31, 2025 ($1.3 million and $15.5 million, respectively for the year ended December 31, 2024).

9. CREDIT FACILITIES

	December 31, 2025	December 31, 2024
Credit facilities - U.S. dollar denominated (1)	**$ 1,400**	$ 206,826
Credit facilities - Canadian dollar denominated	**—**	134,381
Credit facilities - principal (2)	**$ 1,400**	$ 341,207
Unamortized debt issuance costs	**(262)**	(16,861)
Credit facilities	**$ 1,138**	$ 324,346

(1) U.S. dollar denominated credit facilities balance was US$1.0 million as at December 31, 2025 (December 31, 2024 - US$143.6 million).
(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2024 to December 31, 2025 is the result of net repayments of $334.3 million and a decrease in the reported amount of U.S. denominated debt of $5.6 million due to foreign exchange.

On December 19, 2025, concurrent with the closing of the Eagle Ford asset sale, Baytex modified its credit facilities (the "Credit Facilities") to decrease the committed amount to $750 million from US$1.1 billion and extend its maturity to June 27, 2030 from June 27, 2029. There were no changes to the financial covenants as a result of the modification. The Credit Facilities modification was considered significant and the related debt issuance costs were written off to financing and interest in the period.

At December 31, 2025, Baytex had $750 million of revolving credit facilities that mature on June 27, 2030. The Credit Facilities are secured and are comprised of a $50 million operating loan and a $700 million syndicated revolving loan.

The Credit Facilities contain standard commercial covenants, in addition to the financial covenants detailed below, related to debt incurrence, restricted payments, certain transactions and compliance with applicable laws. Noncompliance with these covenants may result in an event of default, at which point the carrying value of the debt could become repayable within a 12-month period after the reporting date. Baytex continues to be in compliance with all financial and commercial covenants under its debt agreements.

Advances under the Baytex Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, Canadian Overnight Repo Rate Average rates or Secured Overnight Financing Rates, plus applicable margins.

The weighted average interest rate on the Credit Facilities was 6.7% for the year ended December 31, 2025 (7.6% for the year ended December 31, 2024).

The following table summarizes the financial covenants applicable to the Credit Facilities and the Company's compliance therewith at December 31, 2025.

Covenant Description	**Position as at December 31, 2025**	**Covenant**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.0:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**4.4:1.0**	3.5:1.0
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**0.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2025, the Company's Senior Secured Debt totaled $5.8 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the year ended December 31, 2025 was $712.4 million.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Financing and interest expenses for the year ended December 31, 2025 was $160.1 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at December 31, 2025, the Company's Total Debt totaled $101.7 million of principal amounts outstanding.

At December 31, 2025, Baytex had $4.4 million of outstanding letters of credit (December 31, 2024 - $5.8 million outstanding).

10. LONG-TERM NOTES

	December 31, 2025	December 31, 2024
8.50% notes due April 30, 2030 (1)	**$ —**	$ 1,152,360
7.375% notes due March 15, 2032 (2)	**95,947**	828,259
Total long-term notes - principal (3)	**$ 95,947**	$ 1,980,619
Unamortized debt issuance costs	**(2,113)**	(47,729)
Total long-term notes - net of unamortized debt issuance costs	**$ 93,834**	$ 1,932,890

(1) The 8.50% notes were fully repaid on December 22, 2025. The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million as at December 31, 2024.

(2) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$70.0 million as at December 31, 2025 (December 31, 2024 - US$575.0 million).

(3) The decrease in the principal amount of long-term notes outstanding from December 31, 2024 to December 31, 2025 is the result of the repurchase and cancellation of US$1.3 billion ($1.8 billion) and changes in the reported amount of U.S. denominated debt of $90.2 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding.

During the year ended December 31, 2025, Baytex repurchased and cancelled US$800.0 million principal amount of the 8.50% Senior Notes at 105.205% of par value and US$505.0 million principal amount of the 7.375% Senior Notes at 103.807% of par value and recorded an early redemption expense of $85.4 million.

On April 1, 2024, Baytex closed a private offering of the US$575.0 million aggregate principal amount of senior unsecured notes due 2032 ("7.375% Senior Notes"), of which US$70.0 million is outstanding as of December 31, 2025. The 7.375% Senior Notes were priced at 99.266% of par to yield 7.500% per annum, bear interest at a rate of 7.375% per annum and mature on March 15, 2032. The 7.375% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices on or after March 15, 2027 and will be redeemable at par from March 15, 2029 to maturity. During 2024, Baytex recorded early redemption expense of $24.4 million which is the call premium paid on the redemption of the 8.75% Senior Notes.

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for debt incurrence, restricted payments, certain transactions and compliance with applicable laws. Noncompliance with these covenants may result in an event of default, at which point the carrying value of the debt could become repayable within a 12 month period after the reporting date. These standard commercial covenants do not prohibit the incurrence of indebtedness under the Credit Facilities, as long as the total debt incurred, including the Credit Facilities, does not exceed a specified threshold. Baytex continues to be in compliance with all financial and commercial covenants under its debt agreements.

11. ASSET RETIREMENT OBLIGATIONS

	December 31, 2025	December 31, 2024
Balance, beginning of year	**$ 640,951**	$ 623,399
Liabilities incurred (1)	**20,794**	32,635
Liabilities settled	**(20,318)**	(28,793)
Liabilities acquired from property acquisitions	**—**	814
Liabilities divested (note 7)	**(104,223)**	(9,482)
Accretion	**23,012**	21,226
Change in estimate (1)	**(7,442)**	10,113
Changes in discount rates and inflation rates (1)(2)	**(24,663)**	(17,495)
Foreign currency translation	**(4,296)**	8,534
Balance, end of year	**$ 523,815**	$ 640,951
Less current portion of asset retirement obligations	**17,138**	15,656
Non-current portion of asset retirement obligations	**$ 506,677**	$ 625,295

(1) The total of these items reflects the total change in asset retirement obligations of $11.3 million per Note 6 - Oil and Gas Properties ($25.3 million increase in 2024).

(1) The discount and inflation rates used to calculate the liability at December 31, 2025 were 3.9% and 2.0% respectively (December 31, 2024 - 3.3% and 1.8%). The discount and inflation rates used prior to the closing of the sale of our U.S. operations on December 19, 2025 were 4.8% and 2.3%, respectively (December 31, 2024 - 4.0% and 2.3%).

At December 31, 2025, the undiscounted, uninflated amount of estimated cash flows required to settle the asset retirement obligations is $674.9 million (December 31, 2024 - $845.0 million). At December 31, 2025, the undiscounted, inflated amount of estimated cash flows required to settle the asset retirement obligations is $915.0 million (December 31, 2024 - $1.2 billion). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2025 is $523.8 million (December 31, 2024 - $641.0 million), with expenditures expected to be incurred over the next 52 years. The estimated timing of these cash flows is summarized in the following table.

	Total	2026-2030	2031-2035	2036-2040	2041 and beyond
Asset retirement obligations	**$ 523,815**	$ 83,024	$ 151,350	$ 107,635	$ 181,806

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2025, no preferred shares have been issued by the Company and all common shares issued were fully paid. The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2023	**821,681**	**$ 6,527,289**
Vesting of share awards	272	1,167
Common shares repurchased and cancelled	(48,363)	(390,977)
Balance, December 31, 2024	**773,590**	**$ 6,137,479**
Vesting of share awards	112	330
Common shares repurchased and cancelled	(8,134)	(65,247)
Balance, December 31, 2025	**765,568**	**$ 6,072,562**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 24, 2025, Baytex announced that the TSX accepted the renewal of the NCIB under which Baytex is permitted to purchase for cancellation up to 66.2 million common shares over the 12-month period commencing July 2, 2025, which represents 10% of the Company's public float, as defined by the TSX, as at June 18, 2025. Baytex obtained an exemption order from the Canadian securities regulators which permits the company to purchase its common shares through the NYSE and other U.S.-based trading systems. On June 18, 2025, Baytex had 768.3 million common shares outstanding.

During the year ended December 31, 2025, Baytex recorded $29.4 million related to common share repurchases, which includes $28.9 million of consideration paid for the repurchase and cancellation of common shares as well as $0.5 million of federal tax levied on equity repurchases.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the year ended December 31, 2025, Baytex repurchased and cancelled 8.1 million common shares at an average price of $3.55 per share for total consideration of $28.9 million. During 2024, Baytex repurchased and cancelled 48.4 million common shares at an average price of $4.50 per share for total consideration of $217.9 million. The total consideration paid includes the commissions and fees paid as part of the transaction and is recorded as a reduction to shareholders' equity. The shares repurchased and cancelled are accounted for as a reduction in shareholders' capital at historical cost, with any discount paid recorded to contributed surplus and any premium paid recorded to retained earnings.

During the year ended December 31, 2025, Baytex recorded a $0.5 million liability related to the 2% federal tax on equity repurchases (December 31, 2024 - $4.3 million), which is charged to shareholders’ capital.

Dividends

The following dividends were declared by Baytex during the year ended December 31, 2025:

Record Date	Payable Date	Per Share Amount		Dividend Amount
March 14, 2025	April 1, 2025	$	0.0225	$ 17,289
June 13, 2025	July 2, 2025		0.0225	17,304
September 15, 2025	October 1, 2025		0.0225	17,326
December 15, 2025	January 2, 2026		0.0225	17,268
Total dividends declared				**$ 69,187**

On March 4, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2026 for shareholders of record on March 13, 2026.

13. SHARE-BASED COMPENSATION PLAN

For the year ended December 31, 2025, the Company recorded share-based compensation expense of $24.0 million ($11.9 million for the year ended December 31, 2024) which is related to the cash-settled awards for continuing operations. For the year ended December 31, 2025, the Company recorded share-based compensation expense of $9.3 million ($6.0 million for the year ended December 31, 2024) which is related to the cash-settled awards for discontinued operations.

The Company's closing share price on December 31, 2025 was $4.44 (December 31, 2024 - $3.70).

The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not exceed 3.8% of the then-issued and outstanding common shares.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at grant date and are subsequently revalued at each period end until the date of settlement. This valuation incorporates the period-end share price, the number of awards outstanding at each period end, and certain management estimates, such as estimated forfeitures and the performance multiplier, if applicable. Share-based compensation expense related to cash-settled awards is recognized in the consolidated statements of income or loss and comprehensive income or loss over the relevant service period with a corresponding increase or decrease in share-based compensation liability. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates of the individual awards.

Share Award Incentive Plan

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "Share Awards") may be granted to directors, officers and employees of the Company and its subsidiaries. Pursuant to the Share Award Incentive Plan, Baytex has the option to settle amounts payable related to Share Awards in cash on the settlement date.

A restricted award entitles the holder of each award to receive one common share of Baytex per restricted award or the equivalent cash value at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares per performance award or the cash equivalent value on vesting; the number of common shares issued is determined by a performance multiplier. The multiplier can range between zero and two and is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The multiplier is dependent on the performance of the Company relative to predefined corporate performance measures for a particular period. The number of Share Awards is adjusted to account for the payment of dividends from the grant date to the applicable issue date. The Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date and are expensed over the vesting period using the graded vesting method. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

The weighted average fair value of Share Awards granted during the year ended December 31, 2025 was $2.92 per restricted and performance award ($4.24 for the year ended December 31, 2024).

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the participants of the plan are entitled to receive a cash payment equal to the value of one Baytex common share per incentive award at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date and are expensed over the vesting period using the graded vesting method. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

The weighted average fair value of share awards granted during the year ended December 31, 2025 was $2.93 per incentive award ($4.34 for the year ended December 31, 2024).

Deferred Share Unit Plan ("DSU Plan")

Baytex has a DSU Plan whereby each independent director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share per DSU award on the date at which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in share-based compensation liability.

The weighted average fair value of share awards granted during the year ended December 31, 2025 was $2.88 per DSU award ($4.46 for the year ended December 31, 2024).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	Director Share Units	Total
Balance, December 31, 2023	**2,279**	**3,355**	**4,483**	**1,245**	**11,362**
Granted	13	2,416	3,671	335	6,435
Added by performance factor	—	524	—	—	524
Vested	(1,457)	(2,449)	(2,577)	(162)	(6,645)
Forfeited	(9)	(364)	(302)	—	(675)
Balance, December 31, 2024	**826**	**3,482**	**5,275**	**1,418**	**11,001**
Granted	5	3,905	5,927	528	10,365
Forfeited by performance factor	—	(243)	—	—	(243)
Vested	(804)	(2,113)	(3,798)	—	(6,715)
Forfeited	(4)	(191)	(1,952)	—	(2,147)
Balance, December 31, 2025	**23**	**4,840**	**5,452**	**1,946**	**12,261**

14. PER SHARE AMOUNTS

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

The following table summarizes the weighted average common shares used in calculating net income or loss per share.

	Years Ended December 31	
(000s)	**2025**	2024
Weighted average common shares - basic	**769,180**	803,435
Dilutive effect of share-based compensation	**—**	4,276
Weighted average common shares - diluted	**769,180**	807,711

For the year ended December 31, 2025, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a loss. For the year ended December 31, 2024, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

15. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's continuing and discontinued operations is set forth in the following table.

	Years Ended December 31	
	2025	2024 (1)
Light oil and condensate	**$ 366,523**	$ 421,383
Heavy oil	**1,261,899**	1,403,022
NGL	**29,583**	26,017
Natural gas	**26,643**	23,624
Total petroleum and natural gas sales - continuing operations	**$ 1,684,648**	$ 1,874,046
Total petroleum and natural gas sales - discontinued operations	**$ 1,888,524**	$ 2,334,909

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 - "Discontinued Operations".

Included in trade receivables at December 31, 2025 is $102.3 million of accrued receivables related to delivered volumes (December 31, 2024 - $325.7 million).

For the year ended December 31, 2025, the Company had four customers that each accounted for 10% or more of total petroleum and natural gas sales for continuing operations. Petroleum and natural gas sales recorded for each of these customers for the year ended December 31, 2025 is summarized in the following table.

	Petroleum and natural gas sales by customer - continuing operations	**% of Total petroleum and natural gas sales - continuing operations**
Customer 1	**$ 360,653**	**21 %**
Customer 2	**$ 275,044**	**16 %**
Customer 3	**$ 218,734**	**13 %**
Customer 4	**$ 210,679**	**13 %**

16. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2025	2024
Net loss before income taxes from continuing operations	**$ (153,110)**	$ (16,718)
Expected income taxes at the statutory rate of 24.16% (2024 – 24.38%) (1)	**(36,991)**	(4,076)
Increase (decrease) in income taxes resulting from:		
Effect of foreign exchange	**(11,022)**	19,354
Effect of change in statutory rates (2)	**—**	8,287
Effect of rate adjustments for foreign jurisdictions	**55**	(3,790)
Effect of change in deferred tax benefit not recognized (3)(4)	**159,299**	38,070
Repatriation and related taxes	**9,639**	17,999
Adjustments, assessments and other	**2,755**	4,891
Income tax expense - continuing operations	**$ 123,735**	$ 80,735

(1) The expected income tax rate decreased due to changes in the provincial apportionment of Canadian income.
(2) On December 11, 2024, Luxembourg enacted a reduction of the statutory corporate income tax rate to 23.87% from 24.94%, applicable to tax years beginning on January 1, 2025. This change resulted in a deferred tax expense in 2024 on the deferred tax assets of Baytex's Luxembourg subsidiary.
(3) A deferred tax asset of $19.9 million remains unrecognized due to uncertainty surrounding future capital gains (December 31, 2024 - $31.8 million). The unrecognized deferred income tax asset relates to realized and unrealized foreign exchange losses arising from the repayment of previously issued U.S. dollar denominated long-term notes and from the translation of U.S. dollar denominated long-term notes currently outstanding.
(4) A deferred tax asset of $587.7 million remains unrecognized due to uncertainty surrounding future income earned in foreign jurisdictions (December 31, 2024 - $99.4 million). The unrecognized deferred tax asset relates to non-capital losses, of which $1.8 billion will expire from 2032 to 2042, and $714 million does not have an expiry date.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency ("CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada (“TCC”) and we estimate it could take another two to three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. Should we be unsuccessful at the TCC, additional appeals are available; a process that we estimate could take another two years and potentially longer.

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During 2023, we purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent statement of account issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $244.2 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. First, the reassessments allege that the trusts were resettled and the resulting successor trusts were not able to access the losses of the predecessor trusts. Second, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. In September 2025, the Department of Justice, legal counsel for the Crown, abandoned the position that the trusts were resettled. The issue of whether the general anti-avoidance rule applies remains in dispute. If, after exhausting available appeals, the deduction of the Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potential penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

For the year-ended December 31, 2025, Baytex has determined that it meets the requirements of safe-harbor provisions in all the jurisdictions in which we operate and therefore does not anticipate owing any top-up taxes under Pillar Two legislation.

A continuity of the net deferred income tax asset or liability is detailed in the following tables:

As at	January 1, 2025	Recognized in Net Loss	Discontinued Operations [3]	Foreign Currency Translation Adjustment	**December 31, 2025**
Taxable temporary differences:					
Petroleum and natural gas properties	$ (848,321)	$ 50,636	$ 562,971	$ 27,955	**$ (206,759)**
Financial derivatives	(5,834)	(566)	—	—	**(6,400)**
Other	(14,599)	14,109	—	—	**(490)**
Deductible temporary differences:					
Asset retirement obligations	153,805	(8,199)	(18,138)	(914)	**126,554**
Non-capital losses [1][2]	648,342	(183,391)	(343,716)	(25,822)	**95,413**
Finance costs	156,258	13,397	(127,119)	(4,510)	**38,026**
Net deferred income tax asset (liability)	$ 89,651	$ (114,014)	$ 73,998	$ (3,291)	**$ 46,344**

(1) Canadian non-capital loss carry-forwards at December 31, 2025 totaled $392.7 million, which will expire from 2033 to 2044.

(2) A deferred income tax asset of $0.5 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.

(3) On December 19, 2025, the Company disposed of its operated and non-operated assets in the Eagle Ford and immediately thereafter liquidated its U.S. subsidiaries, resulting in the extinguishment of the related deferred tax assets and liabilities.

As at		January 1, 2024	Recognized in Net Income	Foreign Currency Translation Adjustment	**December 31, 2024**
Taxable temporary differences:					
Petroleum and natural gas properties	$	(706,101)	$ (100,286)	$ (41,934)	**$ (848,321)**
Financial derivatives		(2,738)	(3,096)	—	**(5,834)**
Other		(13,046)	(1,434)	(119)	**(14,599)**
Deductible temporary differences:					
Asset retirement obligations		150,856	1,138	1,811	**153,805**
Non-capital losses (1)(2)		647,561	(44,671)	45,452	**648,342**
Finance costs		115,280	33,422	7,556	**156,258**
Net deferred income tax asset (liability) (3)	$	191,812	$ (114,927)	$ 12,766	**$ 89,651**

(1) Non-capital loss carry-forwards at December 31, 2024 totaled $3.3 billion. Canadian non-capital loss carry-forwards of $0.4 billion expire between 2034 and 2043. Foreign non-capital loss carry-forwards total $2.9 billion of which $1.4 billion will expire from 2032 to 2040, and $1.5 billion does not have an expiry date.

(2) A deferred income tax asset of $178.2 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.

(3) The net deferred income tax asset as at December 31, 2024 is comprised of a deferred income tax asset of $178.2 million and a deferred income tax liability of $88.6 million.

17. FINANCING AND INTEREST

	Years Ended December 31	
	2025	2024 (1)
Interest on Credit Facilities	**$ 10,885**	$ 38,326
Interest on long-term notes	**149,214**	148,968
Interest on lease obligations	**1,333**	1,338
Cash interest	**$ 161,432**	$ 188,632
Amortization of debt issue costs	**56,116**	14,704
Accretion of asset retirement obligations	**19,114**	17,265
Net early redemption expense	**85,355**	24,350
Financing and interest - continuing operations	**$ 322,017**	$ 244,951
Financing and interest - discontinued operations	**$ 22,985**	$ 23,423

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 - "Discontinued Operations".

18. FOREIGN EXCHANGE

	Years Ended December 31	
	2025	2024 (1)
Unrealized foreign exchange (gain) loss	**$ (88,538)**	$ 153,930
Realized foreign exchange (gain) loss	**(5,481)**	1,965
Foreign exchange (gain) loss - continuing operations	**$ (94,019)**	$ 155,895
Foreign exchange gain - discontinued operations	**$ (3,624)**	$ —

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 - "Discontinued Operations".

19. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade receivables, trade payables, dividends payable, financial derivatives, Credit Facilities and long-term notes. The fair value of cash, trade receivables, trade payables and dividends payable approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2025		December 31, 2024		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 28,898**	**$ 28,898**	$ 25,573	$ 25,573	Level 2
Total	**$ 28,898**	**$ 28,898**	$ 25,573	$ 25,573	
Amortized cost					
Cash	**$ 953,113**	**$ 953,113**	$ 16,610	$ 16,610	—
Trade receivables	**135,230**	**135,230**	387,266	387,266	—
Total	**$ 1,088,343**	**$ 1,088,343**	$ 403,876	$ 403,876	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ (2,406)**	**$ (2,406)**	$ (1,645)	$ (1,645)	Level 2
Total	**$ (2,406)**	**$ (2,406)**	$ (1,645)	$ (1,645)	
Amortized cost					
Trade payables	**$ (236,373)**	**$ (236,373)**	$ (512,473)	$ (512,473)	—
Dividends payable	**(17,268)**	**(17,268)**	(17,598)	(17,598)	—
Credit Facilities (1)	**(1,138)**	**(1,400)**	(324,346)	(341,207)	—
Long-term notes	**(93,834)**	**(99,808)**	(1,932,890)	(1,990,598)	Level 1
Total	**$ (348,613)**	**$ (354,849)**	$ (2,787,307)	$ (2,861,876)	

(1) The difference in the carrying value and fair value of the Credit Facilities is due to unamortized debt issuance costs. Refer to Note 9.

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the number of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2025 or 2024.

Foreign Currency Risk

In entities with a Canadian dollar functional currency, Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its Credit Facilities, long-term notes and crude oil sales based on U.S. dollar benchmark prices. The Company's net income or loss and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities would impact net income or loss before income taxes by approximately $0.6 million.

The carrying amounts of the Company’s U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
U.S. dollar denominated	**US$22,204**	US$21,450	**US$84,500**	US$1,399,881

Commodity Price Risk

Baytex utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives is governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes.

The reported value of commodity financial derivatives is sensitive to changes in forecasted commodity prices. For crude oil contracts outstanding as at December 31, 2025, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately $19.0 million. For natural gas contracts outstanding as at December 31, 2025, a US$0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately $0.9 million.

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at March 4, 2026.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis differential	Jan 2026 to Mar 2026	2,500 bbl/d	WTI less US$13.35/bbl	WCS
Basis differential	Apr 2026 to Jun 2026	2,500 bbl/d	WTI less US$12.55/bbl	WCS
Basis differential	Jul 2026 to Sep 2026	2,500 bbl/d	WTI less US$13.05/bbl	WCS
Basis differential	Jan 2026 to Dec 2026	19,500 bbl/d	WTI less US$13.13/bbl	WCS
Basis differential	Oct 2026 to Dec 2026	2,500 bbl/d	WTI less US$13.75/bbl	WCS
Basis differential	Jan 2026 to Mar 2026	1,000 bbl/d	WTI less US$4.00/bbl	MSW
Basis differential	Apr 2026 to Jun 2026	1,000 bbl/d	WTI less US$3.75/bbl	MSW
Basis differential	Jul 2026 to Sep 2026	1,000 bbl/d	WTI less US$3.50/bbl	MSW
Basis differential	Oct 2026 to Dec 2026	1,000 bbl/d	WTI less US$4.25/bbl	MSW
Purchased put option (2)	Jan 2026 to Jun 2026	2,000 bbl/d	US$60.00/bbl	WTI
Sold call option (2)	Jan 2026 to Jun 2026	2,000 bbl/d	US$70.00/bbl	WTI
Collar (2)	Jan 2026 to Mar 2026	2,000 bbl/d	US$60.00/US$75.00/bbl	WTI
Collar (2)	Jan 2026 to Mar 2026	2,000 bbl/d	US$60.00/US$75.55/bbl	WTI
Collar	Jan 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$67.00/bbl	WTI
Collar	Jan 2026 to Apr 2026	2,500 bbl/d	US$60.00/US$68.00/bbl	WTI
Collar	Jan 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$66.00/bbl	WTI
Collar	Jan 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$64.00/bbl	WTI
Collar	Jan 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$65.00/bbl	WTI
Collar	Jan 2026 to Jun 2026	2,500 bbl/d	US$60.00/US$68.00/bbl	WTI
Natural gas				
Swap	Jan 2026 to Dec 2026	2,000 GJ/d	$3.21/GJ	AECO
Basis differential	Jan 2026 to Dec 2026	2,500 mmbtu/d	NYMEX less US$1.66/mmbtu	NYMEX/AECO
Collar	Jan 2026 to Dec 2026	2,500 mmbtu/d	US$4.00/US$5.10/mmtbu	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contracts include deferred premiums to be paid throughout the contract term. The weighted average deferred premium is $0.70/bbl.

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

	Years Ended December 31	
	2025	2024
Realized financial derivatives loss (gain)	**$ 19,635**	$ (1,447)
Unrealized financial derivatives gain	**(2,564)**	(654)
Financial derivatives loss (gain)	**$ 17,071**	$ (2,101)

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include management of forecasted and actual cash flows from operating, financing and investing activities, available capacity under the existing Credit Facilities, and opportunities to issue additional debt or equity securities.

The timing of undiscounted cash outflows relating to financial liabilities as at December 31, 2025 is outlined in the table below:

	Total	2026	2027-2028	2029-2030	2031 and beyond
Trade payables	**$ 236,373**	$ 236,373	$ —	$ —	$ —
Financial derivatives	**2,406**	2,406	—	—	—
Credit Facilities - principal	**1,400**	—	—	1,400	—
Long-term notes - principal [(1)]	**95,947**	—	—	—	95,947
Interest on long-term notes [(2)]	**43,929**	7,076	14,152	14,152	8,549
Total	**$ 380,055**	**$ 245,855**	**$ 14,152**	**$ 15,552**	**$ 104,496**

(1) The US$70.0 million principal amount of 7.375% senior unsecured notes is due March 15, 2032.
(2) Excludes interest on Credit Facilities as interest payments on Credit Facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2025, the Company is exposed to credit risk with respect to its cash, trade receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade receivables at December 31, 2025 relates to accrued revenues. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade receivables is reduced by adjusting the allowance for doubtful accounts and recording a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2025, allowance for doubtful accounts was $1.1 million (December 31, 2024 - $1.0 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2025 to be nominal.

The Company's trade receivables, net of the allowance for doubtful accounts, were aged as follows:

	December 31, 2025	December 31, 2024
Current (less than 30 days)	**$ 132,257**	$ 383,968
31-60 days	**783**	1,224
61-90 days	**311**	492
Past due (more than 90 days)	**1,879**	1,582
	$ 135,230	$ 387,266

The Company manages credit risk by allocating cash and cash equivalents across major Canadian financial institutions that maintain a minimum investment-grade credit rating, thereby reducing exposure to any single counterparty.

20. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2025	2024
Trade receivables	**$ 257,783**	$ (47,861)
Prepaids and other assets	**(7,275)**	8,531
Trade payables	**(276,100)**	35,178
Share-based compensation liability	**10,070**	(11,000)
Dividends payable	**(330)**	(783)
Non-cash working capital disposed	**49,299**	(6,390)
	$ 33,447	$ (22,325)
Changes in non-cash working capital related to:		
Operating activities	**$ 18,111**	$ (17,922)
Financing activities	**(1,620)**	6,200
Investing activities	**17,822**	(11,375)
Transfers to equity	**(330)**	(1,167)
Foreign currency translation on non-cash working capital	**(536)**	1,939
	$ 33,447	$ (22,325)

Income Statement Presentation

Baytex's consolidated statements of income (loss) and comprehensive income (loss) are prepared according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2025	2024 [(1)]
Operating	**$ 12,372**	$ 13,340
General and administrative	**43,687**	36,583
Total employee compensation costs - continuing operations	**$ 56,059**	$ 49,923
Total employee compensation costs - discontinued operations	**$ 55,670**	$ 38,429

(1) Comparative period revised to reflect current period presentation. Refer to Note 7 - "Discontinued Operations".

21. COMMITMENTS AND CONTINGENCIES

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow (note 23). These obligations as of December 31, 2025 and the expected timing of funding of these obligations, are noted in the table below.

	Total	2026	2027-2028	2029-2030	2031 and beyond
Processing agreements	**$ 4,969**	$ 948	$ 563	$ 533	$ 2,925
Transportation agreements	**134,312**	40,249	51,388	13,416	29,259
Total	**$ 139,281**	**$ 41,197**	**$ 51,951**	**$ 13,949**	**$ 32,184**

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives (note 11). The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

The Company is, from time-to-time, subject to various claims, demands, audits and other proceedings covering matters that arise in the ordinary course of business activities. Such claims and other proceedings often relate to labour, tax, environmental, title or commercial matters. Baytex retains liability for matters related to our prior ownership of assets located in the U.S. Resolution of these matters may have an unfavorable financial or operating impact on the Company. Certain conditions may exist as at December 31, 2025 which may result in a loss to the Company. However, the Company believes that none of these matters are expected to have a material effect on the results of operations or financial position of the Company.

The Company establishes legal provisions for known and potential claims for which payment is probable and can be reliably estimated. The Company also has comprehensive liability insurance coverage; however such insurance does not cover all risks to which we might be exposed and in other cases, may only partially cover losses incurred by the Company.

22. RELATED PARTIES

Transactions with key management personnel and directors are noted in the table below.

	Years Ended December 31	
	2025	2024 [(1)]
Short-term employee benefits	**$ 7,370**	$ 6,460
Share-based compensation	**14,648**	9,761
Total compensation for key management personnel - continuing operations	**$ 22,018**	$ 16,221
Total compensation for key management personnel - discontinued operations	**$ 4,705**	$ 1,154

(1) Comparative period revised to reflect current period presentation.

23. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong financial position that provides flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At December 31, 2025, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time-to-time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital-intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of adjusted funds flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

Net (Cash) Debt

The Company uses net (cash) debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net (cash) debt to be the sum of our Credit Facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash, trade receivables, and prepaids and other assets. Baytex also uses net (cash) debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

The following table reconciles net (cash) debt to amounts disclosed in the primary financial statements.

	December 31, 2025	December 31, 2024
Credit Facilities	**$ 1,138**	$ 324,346
Unamortized debt issuance costs - Credit Facilities (note 9)	**262**	16,861
Long-term notes	**93,834**	1,932,890
Unamortized debt issuance costs - Long-term notes (note 10)	**2,113**	47,729
Trade payables	**236,373**	512,473
Cash	**(953,113)**	(16,610)
Dividends payable	**17,268**	17,598
Share-based compensation liability	**34,802**	24,732
Other long-term liabilities	**—**	20,887
Trade receivables	**(135,230)**	(387,266)
Prepaids and other assets	**(63,232)**	(76,468)
Net (Cash) Debt	**$ (765,785)**	$ 2,417,172

Adjusted Funds Flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirements obligations settled during the applicable period and transaction costs.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Years Ended December 31	
	2025	2024
Cash flows from operating activities	**$ 1,485,962**	$ 1,908,264
Change in non-cash working capital	**(18,111)**	17,922
Asset retirement obligations settled	**20,318**	28,793
Transaction costs	**26,383**	1,539
Adjusted funds flow	**$ 1,514,552**	$ 1,956,518

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standard Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Corporate **Information**

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Chair of the Board

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Director

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Director

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Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [1,4]
Director

Jeffrey E. Wojahn [3,4]
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves and Sustainability Committee
(4) Member of the Nominating and Governance Committee

Officers

Eric T. Greager
Chief Executive Officer

Chad E. Lundberg
President and Chief Operating Officer

Chad L. Kalmakoff
Chief Financial Officer

James R. Maclean
Chief Legal Officer and Corporate Secretary

Brian G. Ector
Senior Vice President, Capital Markets and Investor Relations

Kendall D. Arthur
Senior Vice President and General Manager, Canadian Heavy Oil Operations

Nicole M. Frechette
Vice President and General Manager, Canadian Light Oil Operations

Chris Lessoway
Vice President, Finance and Treasurer

Auditors
KPMG LLP

Reserves Engineers
McDaniel & Associates Consultants Ltd.

Transfer Agent
Odyssey Trust Company

Exchange Listing
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