2024
Q3 REPORT

BAYTEX ANNOUNCES THIRD QUARTER 2024 RESULTS

CALGARY, ALBERTA (October 31, 2024) - Baytex Energy Corp. ("Baytex") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and nine months ended September 30, 2024 (all amounts are in Canadian dollars unless otherwise noted).

"During the third quarter we generated $220 million of free cash flow, returned $101 million to shareholders through our share buyback program and quarterly dividend, and reduced net debt by 5%. Over the last fifteen months we have repurchased 9% of our shares outstanding. Our third quarter results demonstrate continued solid operational performance as well as our commitment to generating meaningful free cash flow and the delivery of strong shareholder returns. We expect to release our 2025 budget in early December. We are committed to prioritizing free cash flow and in the current commodity price environment this means moderating our growth profile and delivering stable crude oil production," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Generated production of 154,468 boe/d (86% oil and NGL) in Q3/2024, up 3% from Q3/2023. Crude oil production (light oil, condensate, and heavy oil) increased 2% from Q3/2023 to average 112,602 bbl/d.
- Increased production per basic share by 10% in Q3/2024, compared to Q3/2023.
- Executed a $306 million exploration and development program in Q3/2024, consistent with our full-year plan.
- Reported cash flows from operating activities of $550 million ($0.69 per basic share) in Q3/2024.
- Delivered adjusted funds flow[(1)] of $538 million ($0.68 per basic share) in Q3/2024.
- Generated net income of $185 million ($0.23 per basic share) in Q3/2024.
- Generated free cash flow[(2)] of $220 million ($0.28 per basic share) in Q3/2024 and returned $101 million to shareholders.
- Repurchased 17.6 million common shares in Q3/2024 for $83 million, at an average price of $4.68 per share.
- Paid a quarterly cash dividend of $18 million ($0.0225 per share) on October 1, 2024.
- Reduced net debt[(1)] by 5% in Q3/2024 and 12% over the last four quarters, to $2.5 billion. Maintained balance sheet strength with a total debt[(3)] to Bank EBITDA[(3)] ratio of 1.0x.

2024 Outlook

We continue to execute our 2024 plan and anticipate full-year 2024 production of approximately 153,000 boe/d (previous guidance range of 152,000 to 154,000 boe/d). We anticipate full-year 2024 exploration and development expenditures of approximately $1.25 billion, consistent with our previous guidance range of $1.2 to $1.3 billion. Based on year-to-date actual results and the forward strip for the balance of 2024[(4)], we expect to generate free cash flow[(2)] of approximately $570 million ($0.71 per basic share) in 2024.

(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 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.
(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(4) Q4/2024 commodity prices: WTI - US$69/bbl; WCS differential - US$14/bbl; NYMEX Gas - US$2.90/MMbtu; and Exchange Rate (CAD/USD) - 1.35.

	Three Months Ended			Nine Months Ended	
	September 30, 2024	June 30, 2024	September 30, 2023	**September 30, 2024**	September 30, 2023
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,074,623**	$ 1,133,123	$ 1,163,010	**$ 3,191,938**	$ 2,317,106
Adjusted funds flow (1)	**537,947**	532,839	581,623	**1,494,632**	1,092,202
Per share – basic	**0.68**	0.65	0.68	**1.84**	1.65
Per share – diluted	**0.67**	0.65	0.68	**1.84**	1.64
Free cash flow (2)	**220,159**	180,673	158,440	**400,744**	252,835
Per share – basic	**0.28**	0.22	0.19	**0.49**	0.38
Per share – diluted	**0.28**	0.22	0.18	**0.49**	0.38
Cash flows from operating activities	**550,042**	505,584	444,033	**1,439,399**	821,279
Per share – basic	**0.69**	0.62	0.52	**1.78**	1.24
Per share – diluted	**0.69**	0.62	0.52	**1.77**	1.23
Net income	**185,219**	103,898	127,430	**275,074**	392,474
Per share – basic	**0.23**	0.13	0.15	**0.34**	0.59
Per share – diluted	**0.23**	0.13	0.15	**0.34**	0.59
Dividends declared	**17,732**	18,161	19,138	**54,387**	19,138
Per share	**0.0225**	0.0225	0.0225	**0.0675**	0.0225
Capital Expenditures					
Exploration and development expenditures	**$ 306,332**	$ 339,573	$ 409,191	**$ 1,058,456**	$ 813,521
Acquisitions and divestitures	**(394)**	654	4,051	**35,638**	4,210
Total oil and natural gas capital expenditures	**$ 305,938**	$ 340,227	$ 413,242	**$ 1,094,094**	$ 817,731
Net Debt					
Credit facilities	**$ 466,108**	$ 625,976	$ 1,046,756	**$ 466,108**	$ 1,046,756
Long-term notes	**1,856,869**	1,881,894	1,637,640	**1,856,869**	1,637,640
Total debt (3)	**2,322,977**	2,507,870	2,684,396	**2,322,977**	2,684,396
Working capital deficiency (2)	**170,292**	131,144	139,952	**170,292**	139,952
Net debt (1)	**$ 2,493,269**	$ 2,639,014	$ 2,824,348	**$ 2,493,269**	$ 2,824,348
Shares Outstanding - basic (thousands)					
Weighted average	**796,064**	814,151	855,300	**810,589**	662,379
End of period	**787,328**	804,977	845,360	**787,328**	845,360
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 75.10**	$ 80.57	$ 82.26	**$ 77.54**	$ 77.39
MEH oil (US$/bbl)	**77.50**	83.10	84.10	**79.85**	78.84
MEH oil differential to WTI (US$/bbl)	**2.40**	2.53	1.84	**2.31**	1.45
Edmonton par ($/bbl)	**97.91**	105.30	107.93	**98.46**	100.70
Edmonton par differential to WTI (US$/bbl)	**(3.30)**	(3.62)	(1.78)	**(5.16)**	(2.54)
WCS heavy oil ($/bbl)	**83.98**	91.72	93.02	**84.45**	80.47
WCS differential to WTI (US$/bbl)	**(13.51)**	(13.55)	(12.89)	**(15.46)**	(17.57)
Natural gas					
NYMEX (US$/MMbtu)	**$ 2.16**	$ 1.89	$ 2.55	**$ 2.10**	$ 2.69
AECO ($/Mcf)	**0.81**	1.44	2.39	**1.43**	3.03
CAD/USD average exchange rate	**1.3636**	1.3684	1.3410	**1.3603**	1.3453

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

	Three Months Ended			Nine Months Ended	
	September 30, 2024	June 30, 2024	September 30, 2023	**September 30, 2024**	September 30, 2023
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**69,843**	67,031	75,763	**67,645**	47,750
Heavy oil (bbl/d)	**42,759**	43,703	35,204	**42,342**	34,076
NGL (bbl/d)	**19,836**	20,167	18,004	**19,767**	11,318
Total liquids (bbl/d)	**132,438**	130,901	128,971	**129,754**	93,144
Natural gas (Mcf/d)	**132,175**	139,764	129,780	**140,069**	96,787
Oil equivalent (boe/d @ 6:1) (1)	**154,468**	154,194	150,600	**153,099**	109,275
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 1,022,721**	$ 1,065,438	$ 1,113,180	**$ 3,008,143**	$ 2,154,600
Royalties	**(223,800)**	(240,440)	(240,049)	**(673,411)**	(441,222)
Operating expense	**(167,119)**	(167,705)	(174,119)	**(508,259)**	(405,965)
Transportation expense	**(36,883)**	(33,314)	(27,983)	**(100,032)**	(59,562)
Operating netback (2)	**$ 594,919**	**$ 623,979**	**$ 671,029**	**$ 1,726,441**	**$ 1,247,851**
General and administrative	**(17,895)**	(21,006)	(20,536)	**(61,313)**	(47,510)
Cash financing and interest	**(50,109)**	(53,946)	(56,495)	**(157,335)**	(103,125)
Realized financial derivatives gain (loss)	**331**	(2,257)	2,055	**3,562**	23,835
Other (3)	**10,701**	(13,931)	(14,430)	**(16,723)**	(28,849)
Adjusted funds flow (4)	**$ 537,947**	**$ 532,839**	**$ 581,623**	**$ 1,494,632**	**$ 1,092,202**
Netback (per boe) (2)					
Total sales, net of blending and other expense (2)	**$ 71.97**	$ 75.93	$ 80.34	**$ 71.71**	$ 72.22
Royalties (5)	**(15.75)**	(17.14)	(17.33)	**(16.05)**	(14.79)
Operating expense (5)	**(11.76)**	(11.95)	(12.57)	**(12.12)**	(13.61)
Transportation expense (5)	**(2.60)**	(2.37)	(2.02)	**(2.38)**	(2.00)
Operating netback (2)	**$ 41.86**	**$ 44.47**	**$ 48.42**	**$ 41.16**	**$ 41.82**
General and administrative (5)	**(1.26)**	(1.50)	(1.48)	**(1.46)**	(1.59)
Cash financing and interest (5)	**(3.53)**	(3.84)	(4.08)	**(3.75)**	(3.46)
Realized financial derivatives (loss) gain (5)	**0.02**	(0.16)	0.15	**0.08**	0.80
Other (3)	**0.76**	(1.00)	(1.03)	**(0.40)**	(0.96)
Adjusted funds flow (4)	**$ 37.85**	**$ 37.97**	**$ 41.98**	**$ 35.63**	**$ 36.61**

Notes:

(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 this press release 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 cash share-based compensation. Refer to the Q3/2024 MD&A for further information on these amounts.

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

(5) Calculated as royalties, operating, 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.

Baytex is a well-capitalized, North American oil-weighted producer with 60% of our production in the Eagle Ford and the balance in western Canada. We are focused on disciplined capital allocation to prioritize free cash flow generation while maintaining a strong balance sheet. We currently allocate 50% of free cash flow to the balance sheet and 50% to shareholder returns, which includes a combination of share buybacks and a quarterly dividend.

The following table summarizes our updated 2024 guidance which reflects year-to-date results and our expectations for the fourth quarter.

	Previous Annual Guidance(1)	Revised Annual Guidance
Production (boe/d)	152,000 - 154,000	~ 153,000
Exploration and development expenditures	$1.2 - $1.3 billion	~ $1.25 billion
Expenses:		
Average royalty rate (2)	~ 23.0%	~ 22.5%
Operating (3)	$11.25 - $12.00/boe	~ $12.00/boe
Transportation (3)	$2.35 - $2.55/boe	~ $2.45/boe
General and administrative (3)	$92 million ($1.65/boe)	$85 million ($1.52/boe)
Interest (3)	$200 million ($3.58/boe)	no change
Current income tax (3)	$40 million ($0.72/boe)	$25 million ($0.45/boe)
Leasing expenditures	$12 million	$15 million
Asset retirement obligations	$30 million	no change

Our 2025 capital budget is expected to be released in early December following approval by our Board of Directors. We are committed to prioritizing free cash flow and in the current commodity price environment this means moderating our growth profile and delivering stable crude oil production.

Financial Highlights

During the third quarter, we delivered operating and financial results consistent with our full-year plan. We increased production per basic share by 10% in Q3/2024, compared to Q3/2023, with production averaging 154,468 boe/d (86% oil and NGL). Exploration and development expenditures totaled $306 million and we brought 82 (69.2 net) wells onstream.

Adjusted funds flow(4) was $538 million or $0.68 per basic share and we generated net income of $185 million ($0.23 per basic share). During the third quarter we recorded approximately $22 million in insurance claim proceeds related to the 2023 Alberta wild fires and prior-period adjustments with respect to previously paid royalties.

During the third quarter we generated free cash flow(2) of $220 million ($0.28 per basic share) and returned $101 million to shareholders. We repurchased 17.6 million common shares for $83 million, at an average price of $4.68 per share, and paid a quarterly cash dividend of $18 million ($0.0225 per share).

Over the last five quarters, we returned $479 million to shareholders. We repurchased 75 million common shares for $387 million, representing 8.7% of our shares outstanding, at an average price of $5.14 per share, and paid total dividends of $92 million ($0.1125 per share).

Continuing to strengthen our balance sheet remains a priority. Our net debt(4) at September 30, 2024 was $2.5 billion, down 5% from June 30, 2024. Over the last four quarters, we reduced our net debt by 12%. Our total debt(5) (excluding working capital) at September 30, 2024 was $2.3 billion.

Operating Results

In the Eagle Ford, production averaged 89,800 boe/d (82% oil and NGL) in Q3/2024, up from 87,311 boe/d (85% oil and NGL) in Q3/2023. We are executing our 2024 development program consistent with our full-year plan. During the third quarter we brought onstream 21 net wells, including 17 net operated wells. Through the first nine months of 2024, we brought onstream 58 net wells, including 46 net operated wells.

(1) As announced on July 25, 2024.
(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 press release for further information.
(3) Calculated as operating, transportation, general and administrative, cash interest expense, or current income tax expense (recovery) divided by barrels of oil equivalent volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(5) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

Our development program is largely focused on the black oil and volatile oil windows of our acreage where we typically generate 30-day peak crude oil rates of 700 to 800 bbl/d (900 to 1,100 boe/d) per well with average lateral lengths of 9,000 to 9,500 feet. Year-to-date, we have realized an 8% improvement in operated drilling and completion costs per completed lateral foot over 2023.

In our Canadian light oil business unit, production averaged 20,428 boe/d (84% oil and NGL) in Q3/2024. We have made substantial strides in advancing our understanding of the Pembina Duvernay and production averaged 7,550 boe/d (83% oil and NGL) in Q3/2024, up from 4,758 boe/d (86% oil and NGL) in Q3/2023. In the Viking, we brought onstream 35 (34.9 net) wells and the asset continues to perform in line with expectations.

In the Pembina Duvernay, we were pleased with the efficiency of our two-pad, seven-well drilling program which saw a 21% improvement in drilling days (spud to rig release) and a 10% improvement in drilling costs. Through a combination of facility and completion design optimization, our average 30-day peak production rates improved by 40%, as compared to 2023 well results, with only a 4% increase in lateral length.

The first pad (3-wells) was brought onstream in May with an average completed lateral length of 11,000 feet and generated an average 30-day peak production rate of 1,354 boe/d per well (890 bbl/d of crude oil, 326 bbl/d of NGLs, 826 Mcf/d of natural gas). The second pad (4-wells) was brought onstream in August with an average completed lateral length of 9,250 feet and generated an average 30-day peak production rate of 968 boe/d per well (725 bbl/d of crude oil, 171 bbl/d of NGLs, 434 Mcf/d of natural gas).

In our heavy oil business unit, production averaged 44,240 boe/d (95% oil and NGL) in Q3/2024, up from 37,506 boe/d (94% oil and NGL) in Q3/2023. Peavine continued to outperform expectations with production averaging 20,085 bbl/d (100% heavy oil) in Q3/2024, up from 13,821 bbl/d (100% heavy oil) in Q3/2023. During the third quarter, we brought onstream 7 (7.0 net) wells. At Peace River, we brought onstream 5 multi-lateral horizontal wells, including one successful Bluesky exploration well on a recently acquired 66-section land block contiguous to our existing acreage position. At Lloydminster, we brought onstream 11 (10.2 net) multi-lateral horizontal wells across the broader Mannville group.

Management Change

Baytex is pleased to announce that Taylor Young has been promoted to Vice President and General Manager, U.S. Eagle Ford Operations. Mr. Young has over 14 years industry experience and holds a Bachelor of Science in Mechanical Engineering from the Colorado School of Mines. He has been with Baytex and its predecessor companies for the last four years, most recently as Director, Subsurface for our U.S. Eagle Ford Operations.

Julia Gwaltney, Senior Vice President and General Manager, U.S. Eagle Ford Operations, has stepped down to pursue another opportunity. Baytex would like to thank Ms. Gwaltney for her contributions and wish her success in her future endeavors.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share, to be paid on January 2, 2025 to shareholders of record on December 13, 2024.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2024 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/edgar.shtml.

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 expect to release our 2025 budget in December 2024; that we are committed to prioritizing free cash flow, maintaining a strong balance sheet and in the current commodity price environment we will moderate our growth profile and deliver stable crude oil production; for 2024: our guidance for exploration and development expenditures and production and the amount of free cash flow we expect to generate; our expected allocation of free cash flow as between the balance sheet and shareholder returns (including share buybacks and quarterly dividends); and our 2024 guidance for expense items, leasing expenditures and asset retirement obligations. 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; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; 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; our ability to market oil and natural gas successfully; 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; 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; risks associated with achieving our total debt target, production guidance, exploration and development expenditures guidance; the amount of free cash flow we expect to generate; risk that the board of directors determines to allocate capital other than as set forth herein; 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; risk that we do not achieve our GHG emissions intensity reduction target; 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. 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.

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, 2023 filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission 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 Company's potential financial position, including, but not limited to, our 2024 guidance for development expenditures; our expected 2024 free cash flow; and our intentions regarding the allocating our annual free cash flow; 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 Company 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 Company 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 Company'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.

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 are subject to the discretion of the Board of Directors of Baytex.

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 deficiency, average royalty rate 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 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 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.

The following table reconciles total sales, net of blending and other expense and operating netback to petroleum and natural gas sales.

	Three Months Ended			Nine Months Ended	
($ thousands)	**September 30, 2024**	June 30, 2024	September 30, 2023	**September 30, 2024**	September 30, 2023
Petroleum and natural gas sales	**$ 1,074,623**	$ 1,133,123	$ 1,163,010	**$ 3,191,938**	$ 2,317,106
Blending and other expense	**(51,902)**	(67,685)	(49,830)	**(183,795)**	(162,506)
Total sales, net of blending and other expense	**$ 1,022,721**	$ 1,065,438	$ 1,113,180	**$ 3,008,143**	$ 2,154,600
Royalties	**(223,800)**	(240,440)	(240,049)	**(673,411)**	(441,222)
Operating expense	**(167,119)**	(167,705)	(174,119)	**(508,259)**	(405,965)
Transportation expense	**(36,883)**	(33,314)	(27,983)	**(100,032)**	(59,562)
Operating netback	**$ 594,919**	$ 623,979	$ 671,029	**$ 1,726,441**	$ 1,247,851
Realized financial derivatives (loss) gain [1]	**331**	(2,257)	2,055	**3,562**	23,835
Operating netback after realized financial derivatives	**$ 595,250**	$ 621,722	$ 673,084	**$ 1,730,003**	$ 1,271,686

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 17 - Financial Instruments and Risk Management in the consolidated financial statements for the three and nine months ended September 30, 2024 and the consolidated financial statements for the six months ended June 30, 2024 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, transaction costs and cash premiums on derivatives.

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

	Three Months Ended			Nine Months Ended	
($ thousands)	**September 30, 2024**	June 30, 2024	September 30, 2023	**September 30, 2024**	September 30, 2023
Cash flows from operating activities	**$ 550,042**	$ 505,584	$ 444,033	**$ 1,439,399**	$ 821,279
Change in non-cash working capital	**(20,813)**	20,140	126,075	**31,350**	205,924
Additions to exploration and evaluation assets	**—**	—	(40)	**—**	(1,271)
Additions to oil and gas properties	**(306,332)**	(339,573)	(409,151)	**(1,058,456)**	(812,250)
Payments on lease obligations	**(2,738)**	(5,478)	(4,740)	**(13,088)**	(7,076)
Transaction costs	**—**	—	2,263	**1,539**	43,966
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Free cash flow	**$ 220,159**	$ 180,673	$ 158,440	**$ 400,744**	$ 252,835

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At September 30, 2024, the Company had $1.0 billion of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**September 30, 2024**	June 30, 2024	December 31, 2023
Cash	**$ (21,311)**	$ (35,887)	$ (55,815)
Trade receivables	**(375,942)**	(429,098)	(339,405)
Prepaids and other assets	**(78,427)**	(81,805)	(83,259)
Trade payables	**584,696**	617,222	477,295
Share-based compensation liability	**23,962**	22,706	35,732
Other long-term liabilities	**19,582**	19,845	19,147
Dividends payable	**17,732**	18,161	18,381
Working capital deficiency	**$ 170,292**	$ 131,144	$ 72,076

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 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 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 debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net 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 debt.

	As at		
($ thousands)	**September 30, 2024**	June 30, 2024	December 31, 2023
Credit facilities	**$ 449,116**	$ 607,589	$ 848,749
Unamortized debt issuance costs - Credit facilities (1)	**16,992**	18,387	15,987
Long-term notes	**1,810,701**	1,833,182	1,562,361
Unamortized debt issuance costs - Long-term notes (1)	**46,168**	48,712	35,114
Trade payables	**584,696**	617,222	477,295
Share-based compensation liability	**23,962**	22,706	35,732
Other long-term liabilities	**19,582**	19,845	19,147
Dividends payable	**17,732**	18,161	18,381
Cash	**(21,311)**	(35,887)	(55,815)
Trade receivables	**(375,942)**	(429,098)	(339,405)
Prepaids and other assets	**(78,427)**	(81,805)	(83,259)
Net debt	**$ 2,493,269**	$ 2,639,014	$ 2,534,287

(1) Unamortized debt issuance costs for the respective periods were obtained from Note 7 - Credit Facilities and Note 8 - Long-term Notes from the consolidated financial statements for the three and nine months ended September 30, 2024 and the consolidated financial statements for the six months ended June 30, 2024.

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, transaction costs and cash premiums on derivatives during the applicable period.

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

	Three Months Ended			Nine Months Ended	
($ thousands)	**September 30, 2024**	June 30, 2024	September 30, 2023	**September 30, 2024**	September 30, 2023
Cash flow from operating activities	**$ 550,042**	$ 505,584	$ 444,033	**$ 1,439,399**	$ 821,279
Change in non-cash working capital	**(20,813)**	20,140	126,075	**31,350**	205,924
Asset retirement obligations settled	**8,718**	7,115	9,252	**22,344**	18,770
Transaction costs	**—**	—	2,263	**1,539**	43,966
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Adjusted funds flow	**$ 537,947**	$ 532,839	$ 581,623	**$ 1,494,632**	$ 1,092,202

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.

References herein to average 30-day peak production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Throughout this press release, "oil and NGL" refers to heavy crude oil, bitumen, light and medium crude 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 nine months ended September 30, 2024. The NI 51-101 product types are included as follows: "Heavy Crude Oil" - heavy crude oil and bitumen, "Light and Medium Crude Oil" - light and medium crude oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended September 30, 2024					Three Months Ended September 30, 2023				
	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,024	13	36	11,959	11,067	9,766	8	45	12,075	11,831
Lloydminster	12,792	19	—	1,659	13,088	11,617	20	—	1,300	11,854
Peavine	20,085	—	—	—	20,085	13,821	—	—	—	13,821
Canada - Light										
Viking	—	9,328	183	9,152	11,036	—	14,074	253	12,015	16,330
Duvernay	—	4,019	2,276	7,529	7,550	—	2,962	1,130	3,996	4,758
Remaining Properties	858	402	38	3,267	1,842	—	577	674	20,672	4,695
United States										
Eagle Ford	—	56,062	17,303	98,609	89,800	—	58,122	15,902	79,722	87,311
Total	42,759	69,843	19,836	132,175	154,468	35,204	75,763	18,004	129,780	150,600

	Nine Months Ended September 30, 2024					Nine Months Ended September 30, 2023				
	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,206	10	41	10,931	11,079	10,113	9	49	11,488	12,086
Lloydminster	13,211	16	—	1,566	13,488	11,554	18	—	1,249	11,780
Peavine	19,211	—	—	—	19,211	12,409	—	—	—	12,409
Canada - Light										
Viking	—	8,881	185	10,264	10,776	—	13,991	210	11,915	16,186
Duvernay	—	2,782	1,892	6,291	5,723	—	1,573	881	2,860	2,931
Remaining Properties	714	434	373	10,110	3,206	—	631	664	19,565	4,556
United States										
Eagle Ford	—	55,522	17,276	100,907	89,616	—	31,528	9,514	49,710	49,327
Total	42,342	67,645	19,767	140,069	153,099	34,076	47,750	11,318	96,787	109,275

Baytex Energy Corp.

Baytex Energy Corp. is an energy company with headquarters based in Calgary, Alberta and offices in Houston, Texas. The Company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. 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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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2024 and 2023
Dated October 31, 2024

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2024. This information is provided as of October 31, 2024. 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 and nine months ended September 30, 2024 ("Q3/2024" and "YTD 2024") have been compared with the results for the three and nine months ended September 30, 2023 ("Q3/2023" and "YTD 2023"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2024, its audited comparative consolidated financial statements for the years ended December 31, 2023 and 2022, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2023. 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.

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 prescribed by the International Accounting Standards Board. 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 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 North American focused oil and gas company based in Calgary, Alberta. The Company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford operated and non-operated assets in Texas.

On June 20, 2023, Baytex and Ranger Oil Corporation ("Ranger") completed a merger of the two companies (the "Merger") whereby Baytex acquired all of the issued and outstanding common shares of Ranger. The Merger increased our Eagle Ford scale and provided an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 80% weighted towards high netback light oil and liquids and is primarily operated which increased our ability to effectively allocate capital.

We issued 311.4 million common shares, paid $732.8 million in cash and assumed $1.1 billion of Ranger's net debt(1). The cash portion of the transaction was funded with an expanded US$1.1 billion credit facility, a US$150 million two-year term loan facility ("Term Loan") (which was fully repaid and cancelled in August 2023) and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030.

THIRD QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q3/2024. Production of 154,468 boe/d for Q3/2024 reflects our successful development programs in the U.S. and Canada. We invested $306.3 million on exploration and development expenditures and generated free cash flow(2) of $220.2 million.

(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.

Exploration and development expenditures totaled $306.3 million in Q3/2024. In the U.S. we invested $185.9 million and production averaged 89,800 boe/d during Q3/2024 compared to exploration and development expenditures of $302.1 million and production of 87,311 boe/d for Q3/2023. In Canada, we invested $120.5 million and generated production of 64,668 boe/d in Q3/2024 compared to exploration and development expenditures of $107.1 million and production of 63,289 boe/d in Q3/2023.

Oil prices declined during Q3/2024 as a result of weaker demand, higher supply and global economic concerns. The WTI benchmark price for Q3/2024 was US$75.10/bbl which was lower than Q3/2023 when WTI averaged US$82.26/bbl. Despite higher production, lower realized pricing resulted in adjusted funds flow[(1)] of $537.9 million and cash flows from operating activities of $550.0 million for Q3/2024 compared to Q3/2023 when we generated adjusted funds flow of $581.6 million and cash flows from operating activities of $444.0 million.

Net debt[(1)] of $2.5 billion at September 30, 2024 was 2% lower than at December 31, 2023 which reflects our allocation of free cash flow to debt repayment in YTD 2024. Free cash flow[(2)] of $400.7 million generated in YTD 2024 was allocated to debt repayment along with $219.6 million of shareholder returns including share buybacks and quarterly dividends. The change in net debt also reflects the impact of a weaker Canadian dollar at September 30, 2024 on our U.S. dollar denominated debt along with $39.8 million of property acquisitions and $49.7 million of debt issuance costs incurred during YTD 2024. We expect net debt to decline over the remainder of 2024 as we continue to allocate 50% of free cash flow to the balance sheet.

(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.

2024 GUIDANCE

We continue to execute our 2024 plan and anticipate full year 2024 production of approximately 153,000 boe/d and exploration and development expenditures of approximately $1.25 billion, consistent with our previous guidance range.

The following table updates our 2024 guidance reflecting year-to-date results and our expectation for the fourth quarter.

	Annual Guidance [(1)]	2024 Revised Guidance
Exploration and development expenditures	$1.2 - $1.3 billion	~ $1.25 billion
Production (boe/d)	152,000 - 154,000	~ 153,000
Expenses:		
Average royalty rate [(2)]	~ 23.0%	~ 22.5%
Operating [(3)]	$11.25 - $12.00/boe	~ $12.00/boe
Transportation [(3)]	$2.35 - $2.55/boe	~ $2.45/boe
General and administrative [(3)]	$92 million ($1.65/boe)	$85 million ($1.52/boe)
Cash interest [(3)]	$200 million ($3.58/boe)	no change
Current income tax [(4)]	$40 million ($0.72/boe)	$25 million ($0.45/boe)
Leasing expenditures	$12 million	$15 million
Asset retirement obligations	$30 million	no change

(1) As announced on July 25, 2024.
(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) 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.
(4) Current income tax expense per boe is calculated as current income tax expense divided by barrels of oil equivalent production volume for the applicable period.

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our operated and non-operated Eagle Ford assets in Texas.

Production

	Three Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**13,781**	**56,062**	**69,843**	17,641	58,122	75,763
Heavy oil	**42,759**	**—**	**42,759**	35,204	—	35,204
Natural Gas Liquids (NGL)	**2,533**	**17,303**	**19,836**	2,102	15,902	18,004
Total liquids (bbl/d)	**59,073**	**73,365**	**132,438**	54,947	74,024	128,971
Natural gas (mcf/d)	**33,566**	**98,609**	**132,175**	50,058	79,722	129,780
Total production (boe/d)	**64,668**	**89,800**	**154,468**	63,289	87,311	150,600
Production Mix						
Segment as a percent of total	**42 %**	**58 %**	**100 %**	42 %	58 %	100 %
Light oil and condensate	**21 %**	**63 %**	**45 %**	28 %	67 %	50 %
Heavy oil	**66 %**	**— %**	**28 %**	56 %	— %	23 %
NGL	**4 %**	**19 %**	**13 %**	3 %	18 %	12 %
Natural gas	**9 %**	**18 %**	**14 %**	13 %	15 %	15 %

	Nine Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**12,123**	**55,522**	**67,645**	16,222	31,528	47,750
Heavy oil	**42,342**	**—**	**42,342**	34,076	—	34,076
Natural Gas Liquids (NGL)	**2,491**	**17,276**	**19,767**	1,804	9,514	11,318
Total liquids (bbl/d)	**56,956**	**72,798**	**129,754**	52,102	41,042	93,144
Natural gas (mcf/d)	**39,162**	**100,907**	**140,069**	47,077	49,710	96,787
Total production (boe/d)	**63,483**	**89,616**	**153,099**	59,948	49,327	109,275
Production Mix						
Segment as a percent of total	**41 %**	**59 %**	**100 %**	55 %	45 %	100 %
Light oil and condensate	**19 %**	**62 %**	**44 %**	27 %	64 %	44 %
Heavy oil	**67 %**	**— %**	**28 %**	57 %	— %	31 %
NGL	**4 %**	**19 %**	**13 %**	3 %	19 %	10 %
Natural gas	**10 %**	**19 %**	**15 %**	13 %	17 %	15 %

Production was 154,468 boe/d for Q3/2024 and 153,099 boe/d for YTD 2024 compared to 150,600 boe/d for Q3/2023 and 109,275 boe/d for YTD 2023. Higher production in Q3/2024 relative to 2023 reflects our successful development programs in the U.S. and Canada. Production for YTD 2024 was higher than the same period of 2023 primarily due to production from the Eagle Ford properties acquired from Ranger in addition to our successful development programs in Canada.

In Canada, production was 64,668 boe/d for Q3/2024 and 63,483 boe/d for YTD 2024 compared to 63,289 boe/d for Q3/2023 and 59,948 boe/d for YTD 2023. Our successful light and heavy oil development programs resulted in a 1,379 boe/d increase in production for Q3/2024 and 3,535 boe/d for YTD 2024 relative to the same periods of 2023. Strong production results from our heavy oil development was partially offset by the disposition of4,000 boe/d of light oil Viking assets in December 2023.

In the U.S., production was 89,800 boe/d for Q3/2024 compared to 87,311 boe/d which reflects the results of our successful development programs. Production of 89,616 boe/d for YTD 2024 was higher than 49,327 boe/d for YTD 2023 due to production from the Merger with Ranger.

Total production of 153,099 boe/d for YTD 2024 is consistent with our revised annual guidance of approximately 153,000 boe/d.

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 pricing for crude oil declined during Q3/2024, influenced by weaker demand, higher supply and global economic concerns. The WTI benchmark price averaged US$75.10/bbl for Q3/2024 and US$77.54/bbl for YTD 2024 compared to US$82.26/bbl for Q3/2023 and US$77.39/bbl for YTD 2023.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf Coast. The MEH benchmark averaged US$77.50/bbl during Q3/2024 and US$79.85/bbl during YTD 2024 compared to US$84.10/bbl for Q3/2023 and US$78.84/bbl for YTD 2023 and typically trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$2.40/bbl and US$2.31/bbl for Q3/2024 and YTD 2024 compared to premiums of US$1.84/bbl and US$1.45/bbl for Q3/2023 and YTD 2023, respectively. The MEH benchmark traded at a higher premium to WTI in both periods of 2024 as a result of additional demand at the U.S. Gulf Coast.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets 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 continued to narrow during Q3/2024 after exports commenced from the TMX pipeline expansion in May 2024. Delays in the TMX expansion resulted in increased pipeline apportionment and additional light and heavy crude oil inventories in the Western Canadian Sedimentary Basin earlier in 2024, which caused wider differentials for YTD 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 $97.91/bbl during Q3/2024 and $98.46/bbl during YTD 2024 compared to $107.93/bbl during Q3/2023 and $100.70/bbl during YTD 2023. Edmonton par traded at a discount to WTI of US$3.30/bbl for Q3/2024 and US$5.16/bbl for YTD 2024 compared to a discount of US$1.78/bbl for Q3/2023 and US$2.54/bbl for YTD 2023.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark for Q3/2024 and YTD 2024 averaged $83.98/bbl and $84.45/bbl respectively, compared to $93.02/bbl and $80.47/bbl for the same periods of 2023. The WCS heavy oil differential to WTI was US$13.51/bbl in Q3/2024 and US$15.46/bbl in YTD 2024 compared to US$12.89/bbl for Q3/2023 and US$17.57/bbl in YTD 2023.

Natural Gas

Natural gas prices in Canada and the U.S. were lower in 2024 relative to 2023 after mild winter weather across most of North America resulted in weak natural gas demand and elevated inventory levels.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$2.16/mmbtu for Q3/2024 and US$2.10/mmbtu for YTD 2024 compared to US$2.55/mmbtu for Q3/2023 and US$2.69/mmbtu for YTD 2023.

In Canada, we receive natural gas pricing 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 $0.81/mcf during Q3/2024 and $1.43/mcf during YTD 2024, lower than $2.39/mcf for Q3/2023 and $3.03/mcf for YTD 2023.

The following tables compare select benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30			Nine Months Ended September 30		
	2024	2023	Change	**2024**	2023	Change
Benchmark Averages						
WTI oil (US$/bbl) (1)	**75.10**	82.26	(7.16)	**77.54**	77.39	0.15
MEH oil (US$/bbl) (2)	**77.50**	84.10	(6.60)	**79.85**	78.84	1.01
MEH oil differential to WTI (US$/bbl)	**2.40**	1.84	0.56	**2.31**	1.45	0.86
Edmonton par oil ($/bbl) (3)	**97.91**	107.93	(10.02)	**98.46**	100.70	(2.24)
Edmonton par oil differential to WTI (US$/bbl)	**(3.30)**	(1.78)	(1.52)	**(5.16)**	(2.54)	(2.62)
WCS heavy oil ($/bbl) (4)	**83.98**	93.02	(9.04)	**84.45**	80.47	3.98
WCS heavy oil differential to WTI (US$/bbl)	**(13.51)**	(12.89)	(0.62)	**(15.46)**	(17.57)	2.11
AECO natural gas ($/mcf) (5)	**0.81**	2.39	(1.58)	**1.43**	3.03	(1.60)
NYMEX natural gas (US$/mmbtu) (6)	**2.16**	2.55	(0.39)	**2.10**	2.69	(0.59)
CAD/USD average exchange rate	**1.3636**	1.3410	0.0226	**1.3603**	1.3453	0.0150

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 96.58**	**$ 101.82**	**$ 100.78**	$ 106.89	$ 109.09	$ 108.57
Heavy oil, net of blending and other expense ($/bbl) (2)	**76.00**	**—**	**76.00**	84.43	—	84.43
NGL ($/bbl) (1)	**26.04**	**27.66**	**27.45**	30.75	28.04	28.36
Natural gas ($/mcf) (1)	**1.00**	**2.53**	**2.14**	2.72	3.20	3.01
Total sales, net of blending and other expense ($/boe) (2)	**$ 72.37**	**$ 71.68**	**$ 71.97**	$ 79.93	$ 80.64	$ 80.34

	Nine Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 96.85**	**$ 104.49**	**$ 103.12**	$ 100.46	$ 105.63	$ 103.87
Heavy oil, net of blending and other expense ($/bbl) (2)	**74.73**	**—**	**74.73**	67.65	—	67.65
NGL ($/bbl) (1)	**25.76**	**27.03**	**26.87**	32.03	28.18	28.79
Natural gas ($/mcf) (1)	**1.61**	**2.42**	**2.20**	2.98	3.21	3.10
Total sales, net of blending and other expense ($/boe) (2)	**$ 70.34**	**$ 72.68**	**$ 71.71**	$ 68.96	$ 76.19	$ 72.22

(1) Calculated as light oil and condensate or NGL sales divided by barrels of oil equivalent production volume for the applicable period, or natural gas sales divided by the production volume in Mcf 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[1] was $71.97/boe for Q3/2024 and $71.71/boe for YTD 2024 compared to $80.34/boe for Q3/2023 and $72.22/boe for YTD 2023. In Canada, our realized price of $72.37/boe for Q3/2024 was $7.56/boe lower than $79.93/boe for Q3/2023. Our realized price in the U.S. was $71.68/boe in Q3/2024 which is $8.96/boe lower than $80.64/boe in Q3/2023. The decrease in North American benchmark prices was the primary factor that resulted in lower realized pricing for our operations in Canada and the U.S. in Q3/2024 and YTD 2024 relative to the same periods of 2023.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price represents a discount to the Edmonton par price of $1.33/bbl for Q3/2024 and $1.61/bbl for YTD 2024 compared to a discount of $1.04/bbl in Q3/2023 and $0.24/bbl for YTD 2023.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $101.82/bbl for Q3/2024 and $104.49/bbl for YTD 2024 compared to $109.09/bbl for Q3/2023 and $105.63/bbl for YTD 2023. Expressed in U.S. dollars, our realized light oil and condensate price of US$74.67/bbl for Q3/2024 and US$76.81/bbl for YTD 2024 represent discounts to MEH of US$2.83/bbl and US$3.04/bbl for Q3/2024 and YTD 2024 respectively, compared to discounts of US$2.75/bbl for Q3/2023 and US$0.32/bbl for YTD 2023. The realized discounts to MEH for 2024 are consistent with expectations and the comparative periods of 2023 which reflect the realized pricing and additional Eagle Ford production acquired from Ranger.

Our realized heavy oil price, net of blending and other expense[1] decreased $8.43/bbl which is consistent with a $9.04/bbl decrease in the WCS benchmark price for the same period. Our realized heavy oil price, net of blending and other expense for YTD 2024 increased by $7.08/bbl from YTD 2023, compared to $3.98/bbl increase in the WCS benchmark price over the same period. Our realized price increased more than the benchmark price as the cost of condensate purchased for blending was lower relative to the price received for sales of the blended product based on the WCS benchmark in YTD 2024 compared to YTD 2023.

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 for the underlying products. Our realized NGL price[2] was $27.45/bbl in Q3/2024 or 27% of WTI (expressed in Canadian dollars) and $26.87/bbl in YTD 2024 or 25% of WTI (expressed in Canadian dollars), compared to $28.36/bbl or 26% of WTI (expressed in Canadian dollars) in Q3/2023 and $28.79/bbl or 28% of WTI (expressed in Canadian dollars) in YTD 2023. Our realized NGL price as a percentage of WTI in both periods of 2024 was consistent with the same periods of 2023.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. The change in our realized natural gas prices in Canada and the U.S. for Q3/2024 and YTD 2024 is consistent with the change in the AECO and NYMEX benchmark prices relative to Q3/2023 and YTD 2023.

(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 or NGL sales divided by barrels of oil equivalent production volume for the applicable period, or natural gas sales divided by the production volume in Mcf for the applicable period.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended September 30					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 122,452**	**$ 525,135**	**$ 647,587**	$ 173,475	$ 583,304	$ 756,779
Heavy oil	**350,859**	**—**	**350,859**	323,272	—	323,272
NGL	**6,067**	**44,034**	**50,101**	5,945	41,027	46,972
Total oil sales	**479,378**	**569,169**	**1,048,547**	502,692	624,331	1,127,023
Natural gas sales	**3,089**	**22,987**	**26,076**	12,526	23,461	35,987
Total petroleum and natural gas sales	**482,467**	**592,156**	**1,074,623**	515,218	647,792	1,163,010
Blending and other expense	**(51,902)**	**—**	**(51,902)**	(49,830)	—	(49,830)
Total sales, net of blending and other expense [(1)]	**$ 430,565**	**$ 592,156**	**$ 1,022,721**	$ 465,388	$ 647,792	$ 1,113,180

	Nine Months Ended September 30					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 321,704**	**$ 1,589,648**	**$ 1,911,352**	$ 444,894	$ 909,159	$ 1,354,053
Heavy oil	**1,050,743**	**—**	**1,050,743**	791,806	—	791,806
NGL	**17,579**	**127,963**	**145,542**	15,777	73,192	88,969
Total oil sales	**1,390,026**	**1,717,611**	**3,107,637**	1,252,477	982,351	2,234,828
Natural gas sales	**17,314**	**66,987**	**84,301**	38,654	43,624	82,278
Total petroleum and natural gas sales	**1,407,340**	**1,784,598**	**3,191,938**	1,291,131	1,025,975	2,317,106
Blending and other expense	**(183,795)**	**—**	**(183,795)**	(162,506)	—	(162,506)
Total sales, net of blending and other expense [(1)]	**$ 1,223,545**	**$ 1,784,598**	**$ 3,008,143**	$ 1,128,625	$ 1,025,975	$ 2,154,600

(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, was $1.0 billion for Q3/2024 which reflects lower realized pricing compared to Q3/2023 when total sales, net of blending and other expense, was $1.1 billion. Total sales, net of blending and other expense of $3.0 billion for YTD 2024 increased from $2.2 billion reported for YTD 2023 which reflects the additional production from the Merger with Ranger.

In Canada, total sales, net of blending and other expense, of $430.6 million for Q3/2024 decreased from $465.4 million reported for Q3/2023. The decrease in our realized pricing for Q3/2024 relative to Q3/2023 resulted in a $45.0 million decrease in total sales, net of blending and other expense while higher production contributed to a $10.1 million increase in total sales, net of blending and other expense, relative to Q3/2023. Total sales, net of blending and other expense, of $1.2 billion for YTD 2024 increased from $1.1 billion for YTD 2023. The increase in our realized pricing for YTD 2024 relative to YTD 2023 resulted in a $24.0 million increase in total sales, net of blending and other expense while higher production contributed to a $70.9 million increase in total sales, net of blending and other expense, relative to YTD 2023.

In the U.S., total petroleum and natural gas sales of $592.2 million for Q3/2024 decreased from $647.8 million reported for Q3/2023. Higher production contributed to a $18.5 million increase in total sales in Q3/2024 relative to Q3/2023 and lower realized pricing resulted in a $74.1 million decrease in total sales relative to Q3/2023. Total petroleum and natural gas sales of $1.8 billion for YTD 2024 increased from $1.0 billion for YTD 2023. Higher production in YTD 2024 resulted in a $844.8 million increase in total sales relative to YTD 2023 and lower realized pricing resulted in a $86.2 million decrease in total sales relative to YTD 2023.

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 for a number of reasons, including 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 three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30					
	2024			2023		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 71,351**	**$ 152,449**	**$ 223,800**	$ 64,238	$ 175,811	$ 240,049
Average royalty rate [1][2]	**16.6 %**	**25.7 %**	**21.9 %**	13.8 %	27.1 %	21.6 %
Royalties per boe [3]	**$ 11.99**	**$ 18.45**	**$ 15.75**	$ 11.03	$ 21.89	$ 17.33

	Nine Months Ended September 30					
	2024			2023		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 200,809**	**$ 472,602**	**$ 673,411**	$ 155,402	$ 285,820	$ 441,222
Average royalty rate [1][2]	**16.4 %**	**26.5 %**	**22.4 %**	13.8 %	27.9 %	20.5 %
Royalties per boe [3]	**$ 11.54**	**$ 19.25**	**$ 16.05**	$ 9.50	$ 21.22	$ 14.79

(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.

Royalties for Q3/2024 were $223.8 million or 21.9% of total sales, net of blending and other expense, compared to $240.0 million or 21.6% for Q3/2023. Total royalties for YTD 2024 were $673.4 million or 22.4% of total sales, net of blending and other expense, compared to $441.2 million or 20.5% for YTD 2023.

Our average royalty rate in Canada of 16.6% for Q3/2024 and 16.4% for YTD 2024 was higher than 13.8% for the comparative periods of 2023 as a result of production growth from our heavy oil properties which have a higher royalty rate relative to our light oil properties.

In the U.S., our average royalty rate was 25.7% for Q3/2024 which was lower than 27.1% for Q3/2023 due to a non-recurring prior period adjustment received from the operator of our non-operated Eagle Ford properties. Our average royalty rate for YTD 2024 was 26.5% compared to 27.9% for YTD 2023 due to the prior period adjustment and production from the acquired Ranger properties which have a lower royalty rate relative to our legacy non-operated Eagle Ford properties.

Our average royalty rate of 22.4% for YTD 2024 is consistent with our revised annual guidance of 22.5% for 2024.

OPERATING EXPENSE

	Three Months Ended September 30					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 87,373**	**$ 79,746**	**$ 167,119**	$ 93,065	$ 81,054	$ 174,119
Operating expense per boe (1)	**$ 14.69**	**$ 9.65**	**$ 11.76**	$ 15.98	$ 10.09	$ 12.57

	Nine Months Ended September 30					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 257,191**	**$ 251,068**	**$ 508,259**	$ 275,599	$ 130,366	$ 405,965
Operating expense per boe (1)	**$ 14.79**	**$ 10.22**	**$ 12.12**	$ 16.84	$ 9.68	$ 13.61

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

Total operating expense was $167.1 million ($11.76/boe) for Q3/2024 which is lower than $174.1 million ($12.57/boe) for Q3/2023, and reflects production growth at Peavine along with the disposition of non-core Viking assets in Q4/2023. Total operating expense of $508.3 million ($12.12/boe) for YTD 2024 was higher than $406.0 million ($13.61/boe) for YTD 2023, due to the additional production from the properties acquired from Ranger which also resulted in lower total per unit operating costs in YTD 2024 relative to YTD 2023.

In Canada, total operating expense was $87.4 million ($14.69/boe) for Q3/2024 and $257.2 million ($14.79/boe) for YTD 2024 which was lower than $93.1 million ($15.98/boe) for Q3/2023 and $275.6 million ($16.84/boe) for YTD 2023. The decrease in total and per unit operating expense for both periods of 2024 relative to the same periods of 2023 reflects production growth at Peavine along with the disposition of non-core Viking assets in Q4/2023.

In the U.S., operating expense was $79.7 million ($9.65/boe) for Q3/2024 which is consistent with $81.1 million ($10.09/boe) for Q3/2023. Operating expense for YTD 2024 increased to $251.1 million ($10.22/boe) from $130.4 million ($9.68/boe) for YTD 2023, which reflects the additional production from the properties acquired from Ranger. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$7.08/boe for Q3/2024 and US$7.51/boe for YTD 2024 consistent with US$7.52/boe for Q3/2023 and US$7.20/boe for YTD 2023.

Operating expense of $12.12/boe for YTD 2024 is consistent with expectations and our annual guidance of approximately $12.00/boe for 2024.

TRANSPORTATION EXPENSE

Transportation expense includes the costs incurred to move production via truck or pipeline to the sales point. Transportation expense can vary from period to period as we seek to optimize sales prices and transportation rates.

The following table compares our transportation expense for the three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 24,837**	**$ 12,046**	**$ 36,883**	$ 16,075	$ 11,908	$ 27,983
Transportation expense per boe (1)	**$ 4.17**	**$ 1.46**	**$ 2.60**	$ 2.76	$ 1.48	$ 2.02

	Nine Months Ended September 30					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 62,616**	**$ 37,416**	**$ 100,032**	$ 46,320	$ 13,242	$ 59,562
Transportation expense per boe (1)	**$ 3.60**	**$ 1.52**	**$ 2.38**	$ 2.83	$ 0.98	$ 2.00

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

Transportation expense was $36.9 million ($2.60/boe) for Q3/2024 and $100.0 million ($2.38/boe) for YTD 2024 compared to $28.0 million ($2.02/boe) for Q3/2023 and $59.6 million ($2.00/boe) for YTD 2023. In Canada, total transportation expense and per unit costs were higher in Q3/2024 and YTD 2024 as a result of additional heavy oil production relative to the same periods of 2023. In the U.S., total transportation expense and per unit costs for Q3/2024 were consistent with Q3/2023 while total transportation and per unit costs for YTD 2024 were higher than YTD 2023 due to trucking and pipeline costs on our operated Eagle Ford operations acquired from Ranger.

Per unit transportation expense of $2.38/boe for YTD 2024 is consistent with our revised annual guidance of approximately $2.45/boe for 2024.

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 was $51.9 million for Q3/2024 and $183.8 million for YTD 2024 compared to $49.8 million for Q3/2023 and $162.5 million for YTD 2023. Higher blending and other expense is primarily a result of higher heavy oil production and pipeline shipments in Q3/2024 and YTD 2024 relative to same periods in 2023.

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 partially 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 executed. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2024**	2023	Change	**2024**	2023	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (2,190)**	$ 2,130	$ (4,320)	**$ (6,091)**	$ 23,909	$ (30,000)
Natural gas	**2,521**	(75)	2,596	**9,653**	(74)	9,727
Total	**$ 331**	$ 2,055	$ (1,724)	**$ 3,562**	$ 23,835	$ (20,273)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 21,239**	$ (31,903)	$ 53,142	**$ 3,251**	$ (39,817)	$ 43,068
Natural gas	**1,357**	1,207	150	**(2,215)**	(1,072)	(1,143)
Total	**$ 22,596**	$ (30,696)	$ 53,292	**$ 1,036**	$ (40,889)	$ 41,925
Total financial derivatives gain (loss)						
Crude oil	**$ 19,049**	$ (29,773)	$ 48,822	**$ (2,840)**	$ (15,908)	$ 13,068
Natural gas	**3,878**	1,132	2,746	**7,438**	(1,146)	8,584
Total	**$ 22,927**	$ (28,641)	$ 51,568	**$ 4,598**	$ (17,054)	$ 21,652

We recorded total financial derivatives gains of $22.9 million for Q3/2024 and $4.6 million for YTD 2024 compared to losses of $28.6 million for Q3/2023 and $17.1 million for YTD 2023. The realized financial derivatives gain of $3.6 million for YTD 2024 resulted from gains of $9.7 million on natural gas contracts and losses of $6.1 million on crude oil contracts. The unrealized financial derivatives gain of $1.0 million for YTD 2024 resulted from a $3.3 million gain on crude oil contracts partially offset by a $2.2 million loss on natural gas contracts. The YTD gain is primarily due to changes in forecasted crude oil and natural gas pricing used to revalue the volumes outstanding on our contracts in place at September 30, 2024 relative to December 31, 2023. The fair value of our financial derivative contracts resulted in a net asset of $24.3 million at September 30, 2024 compared to a net asset of $23.3 million at December 31, 2023.

Refer to Note 17 of the consolidated financial statements for a complete listing of our outstanding contracts at October 31, 2024.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30					
	2024			2023		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**64,668**	**89,800**	**154,468**	63,289	87,311	150,600
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 72.37**	**$ 71.68**	**$ 71.97**	$ 79.93	$ 80.64	$ 80.34
Less:						
Royalties [(2)]	**(11.99)**	**(18.45)**	**(15.75)**	(11.03)	(21.89)	(17.33)
Operating expense [(2)]	**(14.69)**	**(9.65)**	**(11.76)**	(15.98)	(10.09)	(12.57)
Transportation expense [(2)]	**(4.17)**	**(1.46)**	**(2.60)**	(2.76)	(1.48)	(2.02)
Operating netback [(1)]	**$ 41.52**	**$ 42.12**	**$ 41.86**	$ 50.16	$ 47.18	$ 48.42
Realized financial derivatives gain (loss) [(3)]	**—**	**—**	**0.02**	—	—	0.15
Operating netback after financial derivatives [(1)]	**$ 41.52**	**$ 42.12**	**$ 41.88**	$ 50.16	$ 47.18	$ 48.57

	Nine Months Ended September 30					
	2024			2023		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**63,483**	**89,616**	**153,099**	59,948	49,327	109,275
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 70.34**	**$ 72.68**	**$ 71.71**	$ 68.96	$ 76.19	$ 72.22
Less:						
Royalties [(2)]	**(11.54)**	**(19.25)**	**(16.05)**	(9.50)	(21.22)	(14.79)
Operating expense [(2)]	**(14.79)**	**(10.22)**	**(12.12)**	(16.84)	(9.68)	(13.61)
Transportation expense [(2)]	**(3.60)**	**(1.52)**	**(2.38)**	(2.83)	(0.98)	(2.00)
Operating netback [(1)]	**$ 40.41**	**$ 41.69**	**$ 41.16**	$ 39.79	$ 44.31	$ 41.82
Realized financial derivatives gain [(3)]	**—**	**—**	**0.08**	—	—	0.80
Operating netback after financial derivatives [(1)]	**$ 40.41**	**$ 41.69**	**$ 41.24**	$ 39.79	$ 44.31	$ 42.62

(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 of $41.86/boe for Q3/2024 and $41.16/boe for YTD 2024 was lower than $48.42/boe for Q3/2023 and $41.82/boe for YTD 2023 due to the decrease in our realized price which resulted in lower per unit sales net of royalties. In 2024, a higher proportion of our production was from our U.S. properties which have lower operating and transportation expense resulting in total operating and transportation expense of $14.36/boe for Q3/2024 and $14.50/boe for YTD 2024, which was lower than $14.59/boe for Q3/2023 and $15.61/boe for YTD 2023. Our operating netback net of realized gains and losses on financial derivatives was $41.88/boe for Q3/2024 and $41.24/boe for YTD 2024 compared to $48.57/boe for Q3/2023 and $42.62/boe for YTD 2023.

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 three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2024**	2023	Change	**2024**	2023	Change
Gross general and administrative expense	**$ 24,255**	$ 25,970	$ (1,715)	**$ 80,082**	$ 56,863	$ 23,219
Overhead recoveries	**(6,360)**	(5,434)	(926)	**(18,769)**	(9,353)	(9,416)
General and administrative expense	**$ 17,895**	$ 20,536	$ (2,641)	**$ 61,313**	$ 47,510	$ 13,803
General and administrative expense per boe (1)	**$ 1.26**	$ 1.48	$ (0.22)	**$ 1.46**	$ 1.59	$ (0.13)

(1) 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.

G&A expense was $17.9 million ($1.26/boe) for Q3/2024 compared to $20.5 million ($1.48/boe) for Q3/2023 which included higher initial costs related to the Merger. G&A expense was $61.3 million ($1.46/boe) for YTD 2024 compared to $47.5 million ($1.59/boe) for YTD 2023. Higher G&A expense in YTD 2024 compared to YTD 2023 is primarily due to staffing costs associated with the personnel retained following the Merger with Ranger.

G&A expense of $1.46/boe for YTD 2024 is consistent with expectations and we expect G&A expense of approximately $1.52/boe for 2024.

FINANCING AND INTEREST EXPENSE

Financing and interest expense includes interest on our credit facilities, 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 three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2024**	2023	Change	**2024**	2023	Change
Interest on credit facilities	**$ 12,343**	$ 21,671	$ (9,328)	**$ 46,271**	$ 35,422	$ 10,849
Interest on long-term notes	**37,426**	34,664	2,762	**109,760**	67,323	42,437
Interest on lease obligations	**340**	160	180	**1,304**	380	924
Cash interest	**$ 50,109**	$ 56,495	$ (6,386)	**$ 157,335**	$ 103,125	$ 54,210
Accretion of debt issue costs	**3,067**	6,539	(3,472)	**13,989**	8,910	5,079
Accretion of asset retirement obligations	**5,524**	5,031	493	**15,910**	14,252	1,658
Early redemption expense	**—**	—	—	**24,350**	—	24,350
Financing and interest expense	**$ 58,700**	$ 68,065	$ (9,365)	**$ 211,584**	$ 126,287	$ 85,297
Cash interest per boe (1)	**$ 3.53**	$ 4.08	$ (0.55)	**$ 3.75**	$ 3.46	$ 0.29
Financing and interest expense per boe (1)	**$ 4.13**	$ 4.91	$ (0.78)	**$ 5.04**	$ 4.23	$ 0.81

(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.

Financing and interest expense was $58.7 million ($4.13/boe) for Q3/2024 and $211.6 million ($5.04/boe) for YTD 2024 compared to $68.1 million ($4.91/boe) for Q3/2023 and $126.3 million ($4.23/boe) for YTD 2023. The decrease in interest costs in Q3/2024 is due to lower outstanding debt balances compared to Q3/2023. Higher interest costs in YTD 2024 compared to YTD 2023 reflect the additional debt outstanding after the Merger with Ranger and also includes costs incurred related to the early redemption of the 8.75% senior notes on April 1, 2024.

Cash interest of $50.1 million ($3.53/boe) for Q3/2024 was lower than $56.5 million ($4.08/boe) for Q3/2023. Lower interest on our credit facilities reflects lower debt balances outstanding in Q3/2024, while higher interest on long-term notes is a result of the issuance of the 7.375% Senior Notes in Q2/2024. Cash interest of $157.3 million ($3.75/boe) for YTD 2024 was higher than $103.1 million ($3.46/boe) for YTD 2023 and is primarily the result of higher debt balances outstanding after the Merger which included the issuance of US$800.0 million aggregate principal amount of long-term notes. The weighted average interest rate applicable on our credit facilities was 7.5% for Q3/2024 and 7.9% for YTD 2024 compared to 7.8% for Q3/2023 and 7.3% for YTD 2023.

Accretion of asset retirement obligations of $5.5 million for Q3/2024 and $15.9 million for YTD 2024 was consistent with $5.0 million for Q3/2023 and $14.3 million for YTD 2023. Accretion of debt issue costs was higher for 2024 compared to 2023 due to the costs associated with the debt issued in conjunction with the Merger. In Q2/2024 we refinanced our remaining 8.75% senior notes with US$575 million of 7.375% notes and we recorded $24.4 million of early redemption expense.

Cash interest expense of $157.3 million ($3.75/boe) for YTD 2024 is consistent with expectations. Our annual guidance of $200 million ($3.58/boe) for 2024 reflects continued debt repayment and lower interest rates applicable to our credit facilities over the remainder of the year.

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 was $0.1 million for Q3/2024 and $0.7 million for YTD 2024 compared to $0.4 million for Q3/2023 and $0.9 million for YTD 2023.

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 three and nine months ended September 30, 2024 and 2023.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2024**	2023	Change	**2024**	2023	Change
Depletion	**$ 352,745**	$ 317,548	$ 35,197	**$ 1,043,898**	$ 656,456	$ 387,442
Depreciation	**3,639**	2,183	1,456	**9,724**	5,418	4,306
Depletion and depreciation	**$ 356,384**	$ 319,731	$ 36,653	**$ 1,053,622**	$ 661,874	$ 391,748
Depletion and depreciation per boe (1)	**$ 25.08**	$ 23.08	$ 2.00	**$ 25.12**	$ 22.19	$ 2.93

(1) 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.

Depletion and depreciation expense was $356.4 million ($25.08/boe) for Q3/2024 and $1.1 billion ($25.12/boe) for YTD 2024 compared to $319.7 million ($23.08/boe) for Q3/2023 and $661.9 million ($22.19/boe) for YTD 2023. Total depletion and depreciation expense and depletion and depreciation per boe were higher in Q3/2024 and YTD 2024 relative to Q3/2023 and YTD 2023 due to depletion on the assets acquired from Ranger which have a higher depletion rate than our other properties. The effect of the Merger was partially offset by an impairment loss of $833.7 million that was recorded at December 31, 2023.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGUs") at September 30, 2024.

2023 Impairment

At December 31, 2023, we recorded an impairment loss of $833.7 million in our legacy non-operated Eagle Ford CGU due to changes in our reserves and in our Viking CGU due to changes in our reserves and a loss recorded on a disposition of an asset.

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 $2.3 million for Q3/2024 and $17.4 million for YTD 2024 which is lower than $14.7 million for Q3/2023 and $41.4 million for YTD 2023. SBC expense for Q3/2024 and YTD 2024 decreased relative to the same periods of 2023 as YTD 2023 includes $16.2 million of non-cash expense related to awards assumed and settled in Baytex common shares in conjunction with the Merger with Ranger and due to a decrease in the Company's share price during YTD 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.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2024**	2023	Change	**2024**	2023	Change
Unrealized foreign exchange (gain) loss	**$ (24,401)**	$ 42,392	$ (66,793)	**$ 33,506**	$ 29,299	$ 4,207
Realized foreign exchange (gain) loss	**(151)**	290	(441)	**1,934**	1,381	553
Foreign exchange (gain) loss	**$ (24,552)**	$ 42,682	$ (67,234)	**$ 35,440**	$ 30,680	$ 4,760
CAD/USD exchange rates:						
At beginning of period	**1.3687**	1.3238		**1.3205**	1.3534	
At end of period	**1.3505**	1.3537		**1.3505**	1.3537	

We recorded a foreign exchange gain of $24.6 million for Q3/2024 and a loss of $35.4 million for YTD 2024 compared to losses of $42.7 million for Q3/2023 and $30.7 million for YTD 2023.

The unrealized foreign exchange gain of $24.4 million for Q3/2024 is related to changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities due to the strengthening of the Canadian dollar relative to the U.S. dollar at September 30, 2024 compared to June 30, 2024. The loss of $33.5 million for YTD 2024 is due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2024 compared to December 31, 2023. The unrealized foreign exchange loss of $42.4 million for Q3/2023 and $29.3 million for YTD 2023 is related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2023 compared to June 30, 2023 and December 31, 2022.

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 functional currency entities. We recorded a realized foreign exchange gain of $0.2 million for Q3/2024 and a loss of $1.9 million for YTD 2024 compared to losses of $0.3 million for Q3/2023 and $1.4 million for YTD 2023.

INCOME TAXES

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2024**	2023	Change	**2024**	2023	Change
Current income tax (recovery) expense	**$ (3,748)**	$ 808	$ (4,556)	**$ 4,407**	$ 3,278	$ 1,129
Deferred income tax expense (recovery)	**33,577**	48,007	(14,430)	**72,188**	(114,830)	187,018
Total income tax expense (recovery)	**$ 29,829**	$ 48,815	$ (18,986)	**$ 76,595**	$ (111,552)	$ 188,147
Current income tax (recovery) expense per boe	**$ (0.26)**	$ 0.06	$ (0.32)	**$ 0.11**	$ 0.11	$ —

We recorded a current income tax recovery of $3.7 million for Q3/2024 and expense of $4.4 million for YTD 2024 compared to expense of $0.8 million for Q3/2023 and $3.3 million for YTD 2023. The current tax recovery recorded in Q3/2024 and current tax expense in YTD 2024 primarily relates to repatriation and related taxes. The repatriation and related taxes for YTD 2024 have increased from YTD 2023 as a result of the Merger. The current tax recovery recorded in Q3/2024 is a recovery of previously accrued 2023 US taxes. We expect current income tax expense of $25 million ($0.45/boe) for 2024.

We recorded deferred tax expense of $33.6 million for Q3/2024 and $72.2 million for YTD 2024 compared to expense of $48.0 million for Q3/2023 and a recovery of $114.8 million for YTD 2023. The deferred tax expense recorded in Q3/2024 and YTD 2024 reflects income generated on our U.S. operations for the period as the tax pools associated with our Canadian operations are subject to a valuation allowance. The deferred tax expense recorded in Q3/2023 was due to income generated on our Canadian and U.S. operations for the period. The deferred tax recovery recorded in YTD 2023 was primarily related to the effects of the transaction structuring for the Merger in Q2/2023, partially offset by income generated on our Canadian and U.S. operations for the period.

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 Q4/2023, 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 reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $208.6 million as at the date of reassessments 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. If, after exhausting available appeals, the deduction of 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.

NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income for the three and nine months ended September 30, 2024 and 2023 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2024**	2023	Change	**2024**	2023	Change
Petroleum and natural gas sales	**$ 1,074,623**	$ 1,163,010	$ (88,387)	**$ 3,191,938**	$ 2,317,106	$ 874,832
Royalties	**(223,800)**	(240,049)	16,249	**(673,411)**	(441,222)	(232,189)
Revenue, net of royalties	**850,823**	922,961	(72,138)	**2,518,527**	1,875,884	642,643
Expenses						
Operating	**(167,119)**	(174,119)	7,000	**(508,259)**	(405,965)	(102,294)
Transportation	**(36,883)**	(27,983)	(8,900)	**(100,032)**	(59,562)	(40,470)
Blending and other	**(51,902)**	(49,830)	(2,072)	**(183,795)**	(162,506)	(21,289)
Operating netback [(1)]	**$ 594,919**	$ 671,029	$ (76,110)	**$ 1,726,441**	$ 1,247,851	$ 478,590
General and administrative	**(17,895)**	(20,536)	2,641	**(61,313)**	(47,510)	(13,803)
Cash interest	**(50,109)**	(56,495)	6,386	**(157,335)**	(103,125)	(54,210)
Realized financial derivatives gain	**331**	2,055	(1,724)	**3,562**	23,835	(20,273)
Realized foreign exchange gain (loss)	**151**	(290)	441	**(1,934)**	(1,381)	(553)
Cash other income	**9,107**	1,367	7,740	**7,011**	1,013	5,998
Current income tax recovery (expense)	**3,748**	(808)	4,556	**(4,407)**	(3,278)	(1,129)
Cash share-based compensation	**(2,305)**	(14,699)	12,394	**(17,393)**	(25,203)	7,810
Adjusted funds flow [(2)]	**$ 537,947**	$ 581,623	$ (43,676)	**$ 1,494,632**	$ 1,092,202	$ 402,430
Transaction costs	**—**	(2,263)	2,263	**(1,539)**	(43,966)	42,427
Exploration and evaluation	**(82)**	(409)	327	**(749)**	(941)	192
Depletion and depreciation	**(356,384)**	(319,731)	(36,653)	**(1,053,622)**	(661,874)	(391,748)
Non-cash share-based compensation	**—**	—	—	**—**	(16,237)	16,237
Non-cash financing and interest	**(8,591)**	(11,570)	2,979	**(54,249)**	(23,162)	(31,087)
Non-cash other income	**—**	—	—	**—**	1,271	(1,271)
Unrealized financial derivatives gain (loss)	**22,596**	(30,696)	53,292	**1,036**	(40,889)	41,925
Unrealized foreign exchange gain (loss)	**24,401**	(42,392)	66,793	**(33,506)**	(29,299)	(4,207)
(Loss) gain on dispositions and swaps	**(1,091)**	875	(1,966)	**(4,741)**	539	(5,280)
Deferred income tax (expense) recovery	**(33,577)**	(48,007)	14,430	**(72,188)**	114,830	(187,018)
Net income	**$ 185,219**	$ 127,430	$ 57,789	**$ 275,074**	$ 392,474	$ (117,400)

(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.

We generated adjusted funds flow of $537.9 million for Q3/2024 compared $581.6 million for Q3/2023 which reflects lower commodity prices that resulted in decreased revenues net of royalties. Adjusted funds flow was $1.5 billion for YTD 2024 compared to $1.1 billion for YTD 2023 which was primarily due to higher production from the Merger that resulted in increased revenues net of royalties, along with additional operating, transportation and blending and other income. Cash interest and general and administrative expenses were also higher for YTD 2024 due to the additional debt outstanding and staffing levels following the Merger.

We reported net income of $185.2 million for Q3/2024 compared to net income of $127.4 million for Q3/2023. The increase in net income for Q3/2024 is the result of an unrealized foreign exchange gain, an unrealized financial derivatives gain, and a lower deferred income tax expense partially offset by a higher depletion rate and associated depletion expense. We reported net income of $275.1 million for YTD 2024 compared to net income of $392.5 million for YTD 2023. The decrease in net income for YTD 2024 relative to the same periods of 2023 is the result of deferred income tax expense recognized in 2024 compared to a deferred tax recovery recognized in 2023, a higher depletion rate and associated depletion expense, an unrealized foreign exchange loss and increased non-cash financing and interest costs.

OTHER COMPREHENSIVE INCOME

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation loss of $61.6 million for Q3/2024 and gain of $100.9 million for YTD 2024 relates to the change in value of our U.S. net assets and is due to changes in the value of the Canadian dollar relative to the U.S. dollar at September 30, 2024 compared to June 30, 2024 and December 31, 2023. The CAD/USD exchange rate was 1.3505 CAD/USD as at September 30, 2024 compared to 1.3687 CAD/USD at June 30, 2024 and 1.3205 CAD/USD at December 31, 2023.

CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2024 and 2023 are summarized as follows.

	Three Months Ended September 30					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 104,787**	**$ 175,544**	**$ 280,331**	$ 94,555	$ 274,421	$ 368,976
Facilities and other	**15,686**	**10,315**	**26,001**	12,498	27,717	40,215
Exploration and development expenditures	**$ 120,473**	**$ 185,859**	**$ 306,332**	$ 107,053	$ 302,138	$ 409,191
Property acquisitions	**$ 507**	**$ 535**	**$ 1,042**	$ 4,277	$ —	$ 4,277
Proceeds from dispositions	**$ 236**	**$ (1,672)**	**$ (1,436)**	$ (226)	$ —	$ (226)

	Nine Months Ended September 30					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 311,143**	**$ 604,144**	**$ 915,287**	$ 327,026	$ 394,850	$ 721,876
Facilities and other	**69,372**	**73,797**	**143,169**	61,036	30,609	91,645
Exploration and development expenditures	**$ 380,515**	**$ 677,941**	**$ 1,058,456**	$ 388,062	$ 425,459	$ 813,521
Property acquisitions	**$ 36,584**	**$ 3,210**	**$ 39,794**	$ 4,721	$ —	$ 4,721
Proceeds from dispositions	**$ 368**	**$ (4,524)**	**$ (4,156)**	$ (511)	$ —	$ (511)

Exploration and development expenditures of $306.3 million for Q3/2024 were lower than $409.2 million for Q3/2023 and reflects the timing of development activity in our U.S. operations. Exploration and development expenditures were $1.1 billion for YTD 2024 compared to $813.5 million for YTD 2023. The increase for 2024 is primarily due to development activity on our operated Eagle Ford properties acquired from Ranger. We also completed property acquisitions, including the acquisition of 30.75 net sections of Duvernay lands adjacent to our existing acreage, in YTD 2024 for a total of $39.8 million.

In Canada, exploration and development expenditures were $120.5 million in Q3/2024 compared to $107.1 million in Q3/2023 and $380.5 million for YTD 2024 compared to $388.1 million for YTD 2023. Drilling and completion spending of $104.8 million in Q3/2024 was higher than Q3/2023 when we spent $94.6 million which reflects increased development activity levels on our light and heavy oil properties. YTD 2024 drilling and completion spending of $311.1 million reflects light and heavy oil development activity that was consistent with YTD 2023 when we spent $327.0 million. We also invested $69.4 million on facilities and other expenditures during YTD 2024 which is consistent with $61.0 million during YTD 2023.

Total U.S. exploration and development expenditures were $185.9 million for Q3/2024 and $677.9 million for YTD 2024 compared to $302.1 million in Q3/2023 and $425.5 million for YTD 2023. The decrease in exploration and development expenditures for Q3/2024 compared to Q3/2023 reflects cost savings realized on the properties acquired from Ranger, in addition to lower drilling activity. Exploration and development expenditures for YTD 2024 increased compared to YTD 2023 due to additional development related to the operated properties acquired from Ranger.

Exploration and development expenditures of $1.1 billion for YTD 2024 were consistent with expectations. Our revised annual guidance of approximately $1.25 billion reflects moderated exploration and development spending over the remainder of 2024.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. We strive to actively manage our capital structure in response to changes in economic conditions. At September 30, 2024, 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 debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Management of debt levels is a priority for Baytex in order to sustain operations and support our business strategy. Net debt(1) of $2.5 billion at September 30, 2024 was consistent with $2.5 billion at December 31, 2023 which was due to the impact of a weaker Canadian dollar at September 30, 2024 on our U.S. dollar denominated debt and also reflects $39.8 million of property acquisitions along with $49.7 million of debt issuance costs incurred during YTD 2024, which included $24.4 million of early redemption expense. We expect net debt to decline over the remainder of 2024 as we continue to allocate 50% of free cash flow to the balance sheet.

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

Credit Facilities

At September 30, 2024, we had $466.1 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.5 billion) (the "Credit Facilities"). The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. On May 9, 2024, we extended the maturity of the Credit Facilities from April 1, 2026 to May 9, 2028. There were no changes to the loan balances or financial covenants as a result of the amendment. Following the amendment, borrowing in Canadian funds previously based on the banker's acceptance rate has been replaced with borrowings based on the Canadian Overnight Repo Rate Average ("CORRA").

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 bank’s prime lending rate, CORRA rates or secured overnight financing rates ("SOFR"), plus applicable margins. Advances under the Baytex Energy USA, Inc. Credit Facilities can be drawn in U.S. funds and bear interest at the bank's prime lending rate or SOFR, plus applicable margins.

The weighted average interest rate on the Credit Facilities was 7.5% for Q3/2024 and 7.9% for YTD 2024, which is consistent with 7.8% for Q3/2023 and 7.3% for YTD 2023.

At September 30, 2024, we had $5.7 million of outstanding letters of credit (December 31, 2023 - $5.6 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 September 30, 2024.

Covenant Description	Position as at September 30, 2024	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.2:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**10.5:1.0**	3.5:1.0
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**1.0:1.0**	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 September 30, 2024, the Company's Senior Secured Debt totaled $470.8 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 acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2024 was $2.2 billion.

(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 expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended September 30, 2024 was $212.4 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 September 30, 2024, the Company's Total Debt totaled $2.3 billion of principal amounts outstanding.

Long-Term Notes

At September 30, 2024 we have two issuances of long-term notes outstanding with a total principal amount of $1.9 billion. The long-term notes do not contain any financial maintenance covenants.

On April 27, 2023, we issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity. At September 30, 2024 there was US$800.0 million aggregate principal amount of the 8.50% Senior Notes outstanding.

On April 1, 2024, we closed a private offering of the US$575 million aggregate principal amount of senior unsecured notes due 2032 ("7.375% Senior Notes"). 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. Proceeds from the 7.375% Senior Notes were used to redeem the remaining US$409.8 million aggregate principal amount of the outstanding 8.75% Senior Notes at 104.375% of par value, pay the related fees and expenses associated with the offering, and repay a portion of the debt outstanding on our Credit Facilities. At September 30, 2024 there was US$575.0 million aggregate principal amount of the 7.375% Senior Notes outstanding.

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 nine months ended September 30, 2024, we issued 0.3 million common shares pursuant to our share-based compensation program. As at September 30, 2024, we had 787.3 million common shares issued and outstanding and no preferred shares issued and outstanding.

Our shareholder returns framework includes common share repurchases and a quarterly dividend. During the nine months ended September 30, 2024, we repurchased 34.6 million common shares under our normal course issuer bid ("NCIB") at an average price of $4.77 per share for total consideration of $165.2 million. In June 2024, we renewed our NCIB under which Baytex is permitted to purchase for cancellation up to 70.1 million common shares over the 12-month period commencing July 2, 2024, which represents 10% of Baytex's public float, as defined by the TSX, as of June 18, 2024. 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.

Effective January 1, 2024, the Government of Canada introduced a 2% federal tax on equity repurchases. During the nine months ended September 30, 2024, Baytex recorded a $3.3 million liability, charged to shareholders’ capital, related to the federal tax on equity repurchases.

On January 2, April 1, July 2, and October 1, 2024, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On October 31, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 2, 2025 for shareholders of record on December 13, 2024. 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

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 September 30, 2024 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Credit facilities - principal	**$ 466,108**	$ —	$ —	$ 466,108	$ —
Long-term notes - principal	**1,856,869**	—	—	—	1,856,869
Interest on long-term notes (1)	**939,973**	149,098	298,196	298,196	194,483
Lease obligations - principal	**28,135**	9,120	9,057	7,139	2,819
Processing agreements	**5,178**	530	850	543	3,255
Transportation agreements	**177,670**	53,710	86,796	24,646	12,518
Total	**$ 3,473,933**	$ 212,458	$ 394,899	$ 796,632	$ 2,069,944

(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.

QUARTERLY FINANCIAL INFORMATION

	2024			2023				2022
($ thousands, except per common share amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**1,074,623**	1,133,123	984,192	1,065,515	1,163,010	598,760	555,336	648,986
Net income (loss)	**185,219**	103,898	(14,043)	(625,830)	127,430	213,603	51,441	352,807
Per common share - basic	**0.23**	0.13	(0.02)	(0.75)	0.15	0.37	0.09	0.65
Per common share - diluted	**0.23**	0.13	(0.02)	(0.75)	0.15	0.36	0.09	0.64
Adjusted funds flow (1)	**537,947**	532,839	423,846	502,148	581,623	273,590	236,989	255,552
Per common share - basic	**0.68**	0.65	0.52	0.60	0.68	0.47	0.43	0.47
Per common share - diluted	**0.67**	0.65	0.52	0.60	0.68	0.47	0.43	0.46
Free cash flow (2)	**220,159**	180,673	(88)	290,785	158,440	96,313	(1,918)	143,324
Per common share - basic	**0.28**	0.22	—	0.35	0.19	0.17	—	0.26
Per common share - diluted	**0.28**	0.22	—	0.35	0.18	0.16	—	0.26
Cash flows from operating activities	**550,042**	505,584	383,773	474,452	444,033	192,308	184,938	303,441
Per common share - basic	**0.69**	0.62	0.47	0.57	0.52	0.33	0.34	0.56
Per common share - diluted	**0.69**	0.62	0.47	0.57	0.52	0.33	0.34	0.55
Dividends declared	**17,732**	18,161	18,494	18,381	19,138	—	—	—
Per common share	**0.0225**	0.0225	0.0225	0.0225	0.0225	—	—	—
Exploration and development	**306,332**	339,573	412,551	199,214	409,191	170,704	233,626	103,634
Canada	**120,473**	101,916	158,126	75,137	107,053	96,403	184,606	85,641
U.S.	**185,859**	237,657	254,425	124,077	302,138	74,301	49,020	17,993
Property acquisitions	**1,042**	3,349	35,403	33,923	4,277	(62)	506	1,085
Proceeds from dispositions	**(1,436)**	(2,695)	(25)	(159,745)	(226)	(50)	(235)	(148)
Net debt (1)	**2,493,269**	2,639,014	2,639,841	2,534,287	2,824,348	2,814,844	995,170	987,446
Total assets	**7,614,157**	7,770,926	7,717,495	7,460,931	8,946,181	8,617,444	5,180,059	5,103,769
Common shares outstanding	**787,328**	804,977	821,322	821,681	845,360	862,192	545,553	544,930
Daily production								
Total production (boe/d)	**154,468**	154,194	150,620	160,373	150,600	89,761	86,760	86,864
Canada (boe/d)	**64,668**	63,688	62,081	64,744	63,289	55,874	60,651	56,946
U.S. (boe/d)	**89,800**	90,506	88,540	95,629	87,311	33,887	26,109	29,918
Benchmark prices								
WTI oil (US$/bbl)	**75.10**	80.57	76.96	78.32	82.26	73.78	76.13	82.64
WCS heavy oil ($/bbl)	**83.98**	91.72	77.73	76.86	93.02	78.85	69.44	77.37
Edmonton par oil ($/bbl)	**97.91**	105.30	92.16	99.72	107.93	95.13	99.04	109.57
CAD/USD avg exchange rate	**1.3636**	1.3684	1.3488	1.3619	1.3410	1.3431	1.3520	1.3577
AECO natural gas ($/mcf)	**0.81**	1.44	2.05	2.66	2.39	2.35	4.34	5.58
NYMEX natural gas (US$/mmbtu)	**2.16**	1.89	2.24	2.88	2.55	2.10	3.42	6.26
Total sales, net of blending and other expense ($/boe) (2)	**71.97**	75.93	67.12	68.00	80.34	66.82	63.48	74.93
Royalties ($/boe) (3)	**(15.75)**	(17.14)	(15.26)	(15.49)	(17.33)	(13.21)	(11.94)	(15.23)
Operating expense ($/boe) (3)	**(11.76)**	(11.95)	(12.65)	(11.17)	(12.57)	(14.62)	(14.40)	(13.06)
Transportation expense ($/boe) (3)	**(2.60)**	(2.37)	(2.18)	(2.02)	(2.02)	(1.78)	(2.18)	(1.85)
Operating netback ($/boe) (2)	**41.86**	44.47	37.03	39.32	48.42	37.21	34.96	44.79
Financial derivatives gain (loss) ($/boe) (3)	**0.02**	(0.16)	0.40	0.84	0.15	2.00	0.69	(6.21)
Operating netback after financial derivatives ($/boe) (2)	**41.88**	44.31	37.43	40.16	48.57	39.21	35.65	38.58

(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) Calculated as royalties, operating expense, 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 remained relatively stable. Production steadily increased from 86,864 boe/d in Q4/2022 and reached 154,468 boe/d in Q3/2024 due to strong well performance from our development programs in Canada and the U.S., along with the production contribution from the Merger with Ranger.

Crude oil prices strengthened in Q3/2023 as a result of the announcement by OPEC+ of new production cuts, as well as the extension of voluntary production cuts by Saudi Arabia and Russia. This was reflected in our realized sales price of $80.34/boe for Q3/2023, which is our strongest realized pricing in the most recent eight quarters. Our realized price of $71.97/boe for Q3/2024 reflects lower crude oil prices due to concerns over weaker demand, higher inventories and slowing global economic activity.

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 $537.9 million and cash flows from operating activities of $550.0 million for Q3/2024 reflect strong production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) increased to $2.5 billion at Q3/2024 from $1.0 billion at Q4/2022 as a result of additional debt used to fund the Merger which closed in Q2/2023. The change in net debt also reflects free cash flow(2) of $944.4 million generated in the period since Q4/2022, along with $479.0 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, 2023 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 proposed standards that are aligned with the ISSB release, but include suggestions for Canadian-specific modifications. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. 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 financial arrangements that are excluded from the consolidated financial statements as at September 30, 2024, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the nine months ended September 30, 2024. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2023.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2024, Baytex adopted amendments to IAS 1 *Presentation of Financial Statements* which was issued by the IASB in January 2020. The amendments further clarify the requirements for the presentation of liabilities as current or non-current in the consolidated statements of financial position.

These amendments have not had a material impact on our consolidated financial statements.

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 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 in the following table.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2024**	2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,074,623**	$ 1,163,010	**$ 3,191,938**	$ 2,317,106
Light oil and condensate [1]	**(647,587)**	(756,779)	**(1,911,352)**	(1,354,053)
NGL [1]	**(50,101)**	(46,972)	**(145,542)**	(88,969)
Natural gas sales [1]	**(26,076)**	(35,987)	**(84,301)**	(82,278)
Heavy oil sales	**$ 350,859**	$ 323,272	**$ 1,050,743**	$ 791,806
Blending and other expense [2]	**(51,902)**	(49,830)	**(183,795)**	(162,506)
Heavy oil, net of blending and other expense	**$ 298,957**	$ 273,442	**$ 866,948**	$ 629,300

(1) Component of petroleum and natural gas sales. See Note 13 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three and nine months ended September 30, 2024 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.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2024**	2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,074,623**	$ 1,163,010	**$ 3,191,938**	$ 2,317,106
Blending and other expense	**(51,902)**	(49,830)	**(183,795)**	(162,506)
Total sales, net of blending and other expense	**1,022,721**	1,113,180	**3,008,143**	2,154,600
Royalties	**(223,800)**	(240,049)	**(673,411)**	(441,222)
Operating expense	**(167,119)**	(174,119)	**(508,259)**	(405,965)
Transportation expense	**(36,883)**	(27,983)	**(100,032)**	(59,562)
Operating netback	**$ 594,919**	$ 671,029	**$ 1,726,441**	$ 1,247,851
Realized financial derivatives gain (1)	**331**	2,055	**3,562**	23,835
Operating netback after realized financial derivatives	**$ 595,250**	$ 673,084	**$ 1,730,003**	$ 1,271,686

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 17 - Financial Instruments and Risk Management in the consolidated financial statements for the three and nine months ended September 30, 2024 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, transaction costs and cash premiums on derivatives.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2024**	2023	**2024**	2023
Cash flows from operating activities	**$ 550,042**	$ 444,033	**$ 1,439,399**	$ 821,279
Change in non-cash working capital	**(20,813)**	126,075	**31,350**	205,924
Additions to exploration and evaluation assets	**—**	(40)	**—**	(1,271)
Additions to oil and gas properties	**(306,332)**	(409,151)	**(1,058,456)**	(812,250)
Payments on lease obligations	**(2,738)**	(4,740)	**(13,088)**	(7,076)
Transaction costs	**—**	2,263	**1,539**	43,966
Cash premiums on derivatives	**—**	—	**—**	2,263
Free cash flow	**$ 220,159**	$ 158,440	**$ 400,744**	$ 252,835

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 debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net 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 debt.

	As at	
($ thousands)	**September 30, 2024**	December 31, 2023
Credit facilities	**$ 449,116**	$ 848,749
Unamortized debt issuance costs - Credit facilities [1]	**16,992**	15,987
Long-term notes	**1,810,701**	1,562,361
Unamortized debt issuance costs - Long-term notes [1]	**46,168**	35,114
Trade payables	**584,696**	477,295
Share-based compensation liability	**23,962**	35,732
Dividends payable	**17,732**	18,381
Other long-term liabilities	**19,582**	19,147
Cash	**(21,311)**	(55,815)
Trade receivables	**(375,942)**	(339,405)
Prepaids and other assets	**(78,427)**	(83,259)
Net debt	**$ 2,493,269**	$ 2,534,287

(1) *Unamortized debt issuance costs were obtained from Note 7 - Credit Facilities and Note 8 - Long-term Notes from the consolidated financial statements for the three and nine months ended September 30, 2024. 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 September 30		Nine Months Ended September 30	
($ thousands)	**2024**	2023	**2024**	2023
Cash flow from operating activities	**$ 550,042**	$ 444,033	**$ 1,439,399**	$ 821,279
Change in non-cash working capital	**(20,813)**	126,075	**31,350**	205,924
Asset retirement obligations settled	**8,718**	9,252	**22,344**	18,770
Transaction costs	**—**	2,263	**1,539**	43,966
Cash premiums on derivatives	**—**	—	**—**	2,263
Adjusted funds flow	**$ 537,947**	$ 581,623	**$ 1,494,632**	$ 1,092,202

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or that changes were made to, internal controls over financial reporting during the three months ended September 30, 2024.

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: that we can effectively allocate capital across our assets; our 2024 guidance for: exploration and development expenditures, average daily production, royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, current income taxes, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; that we intend to settle outstanding share based compensation awards in cash; the expected time to resolve the reassessment of our tax filings by the Canada Revenue Agency; our objective to maintain a strong balance sheet to execute development programs, deliver shareholder returns and optimize our portfolio through strategic acquisitions; that we may issue or repurchase debt or equity securities from time to time; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the financial obligations. 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; 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, 2023, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission 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.

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

	Notes	As at September 30, 2024	As at December 31, 2023
ASSETS			
Current assets			
Cash		$ **21,311**	$ 55,815
Trade receivables	13, 17	**375,942**	339,405
Prepaids and other assets		**21,632**	21,530
Financial derivatives	17	**24,310**	23,274
		443,195	440,024
Non-current assets			
Exploration and evaluation assets	5	**122,124**	90,919
Oil and gas properties	6	**6,776,336**	6,619,033
Other plant and equipment		**8,621**	7,936
Lease assets		**21,174**	28,145
Prepaids and other assets	14	**56,795**	61,729
Deferred income tax asset	14	**185,912**	213,145
		$ **7,614,157**	$ 7,460,931
LIABILITIES			
Current liabilities			
Trade payables	17	$ **584,696**	$ 477,295
Share-based compensation liability	11	**18,340**	28,508
Dividends payable	10, 17	**17,732**	18,381
Lease obligations		**7,536**	13,391
Asset retirement obligations	9	**17,512**	20,448
		645,816	558,023
Non-current liabilities			
Other long-term liabilities		**19,582**	19,147
Share-based compensation liability	11	**5,622**	7,224
Credit facilities	7	**449,116**	848,749
Long-term notes	8	**1,810,701**	1,562,361
Lease obligations		**16,117**	16,056
Asset retirement obligations	9	**626,339**	602,951
Deferred income tax liability	14	**61,449**	21,333
		3,634,742	3,635,844
SHAREHOLDERS’ EQUITY			
Shareholders' capital	10	**6,248,284**	6,527,289
Contributed surplus		**304,781**	193,077
Accumulated other comprehensive income		**791,859**	690,917
Deficit		**(3,365,509)**	(3,586,196)
		3,979,415	3,825,087
		$ **7,614,157**	$ 7,460,931

Subsequent events (notes 10 and 17)

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Three Months Ended September 30		Nine Months Ended September 30	
		2024	2023	**2024**	2023
Revenue, net of royalties					
Petroleum and natural gas sales	13	**$ 1,074,623**	$ 1,163,010	**$ 3,191,938**	$ 2,317,106
Royalties		**(223,800)**	(240,049)	**(673,411)**	(441,222)
		850,823	922,961	**2,518,527**	1,875,884
Expenses					
Operating		**167,119**	174,119	**508,259**	405,965
Transportation		**36,883**	27,983	**100,032**	59,562
Blending and other		**51,902**	49,830	**183,795**	162,506
General and administrative		**17,895**	20,536	**61,313**	47,510
Transaction costs		**—**	2,263	**1,539**	43,966
Exploration and evaluation	5	**82**	409	**749**	941
Depletion and depreciation		**356,384**	319,731	**1,053,622**	661,874
Share-based compensation	11	**2,305**	14,699	**17,393**	41,440
Financing and interest	15	**58,700**	68,065	**211,584**	126,287
Financial derivatives (gain) loss	17	**(22,927)**	28,641	**(4,598)**	17,054
Foreign exchange (gain) loss	16	**(24,552)**	42,682	**35,440**	30,680
Loss (gain) on dispositions and property swaps		**1,091**	(875)	**4,741**	(539)
Other income		**(9,107)**	(1,367)	**(7,011)**	(2,284)
		635,775	746,716	**2,166,858**	1,594,962
Net income before income taxes		**215,048**	176,245	**351,669**	280,922
Income tax expense (recovery)	14				
Current income tax (recovery) expense		**(3,748)**	808	**4,407**	3,278
Deferred income tax expense (recovery)		**33,577**	48,007	**72,188**	(114,830)
		29,829	48,815	**76,595**	(111,552)
Net income		**$ 185,219**	$ 127,430	**$ 275,074**	$ 392,474
Other comprehensive (loss) income					
Foreign currency translation adjustment		**(61,640)**	111,981	**100,942**	64,976
Comprehensive income		**$ 123,579**	$ 239,411	**$ 376,016**	$ 457,450
Net income per common share	12				
Basic		**$ 0.23**	$ 0.15	**$ 0.34**	$ 0.59
Diluted		**$ 0.23**	$ 0.15	**$ 0.34**	$ 0.59
Weighted average common shares (000's)	12				
Basic		**796,064**	855,300	**810,589**	662,379
Diluted		**800,217**	860,572	**814,351**	666,194

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Issued on corporate acquisition		1,326,435	21,316	—	—	**1,347,751**
Vesting of share awards		26,229	(37,462)	—	—	**(11,233)**
Share-based compensation		—	16,237	—	—	**16,237**
Repurchase of common shares for cancellation		(134,695)	45,429	—	—	**(89,266)**
Dividends declared		—	—	—	(19,138)	**(19,138)**
Comprehensive income		—	—	64,976	392,474	**457,450**
Balance at September 30, 2023		$ 6,717,633	$ 135,399	$ 821,171	$ (2,941,985)	**$ 4,732,218**
Balance at December 31, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**
Vesting of share awards	10	1,167	—	—	—	**1,167**
Repurchase of common shares for cancellation	10	(280,172)	111,704	—	—	**(168,468)**
Dividends declared	10	—	—	—	(54,387)	**(54,387)**
Comprehensive income		—	—	100,942	275,074	**376,016**
Balance at September 30, 2024		$ 6,248,284	$ 304,781	$ 791,859	$ (3,365,509)	**$ 3,979,415**

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Three Months Ended September 30 2024	Three Months Ended September 30 2023	Nine Months Ended September 30 2024	Nine Months Ended September 30 2023
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 185,219**	$ 127,430	**$ 275,074**	$ 392,474
Adjustments for:					
Non-cash share-based compensation	11	**—**	—	**—**	16,237
Unrealized foreign exchange (gain) loss	16	**(24,401)**	42,392	**33,506**	29,299
Exploration and evaluation	5	**82**	409	**749**	941
Depletion and depreciation		**356,384**	319,731	**1,053,622**	661,874
Non-cash financing and interest	15	**8,591**	11,570	**54,249**	23,162
Non-cash other income	9	**—**	—	**—**	(1,271)
Unrealized financial derivatives (gain) loss	17	**(22,596)**	30,696	**(1,036)**	40,889
Cash premiums on derivatives		**—**	—	**—**	(2,263)
Loss (gain) on dispositions and property swaps		**1,091**	(875)	**4,741**	(539)
Deferred income tax expense (recovery)	14	**33,577**	48,007	**72,188**	(114,830)
Asset retirement obligations settled	9	**(8,718)**	(9,252)	**(22,344)**	(18,770)
Change in non-cash working capital		**20,813**	(126,075)	**(31,350)**	(205,924)
Cash flows from operating activities		**550,042**	444,033	**1,439,399**	821,279
Financing activities					
(Decrease) increase in credit facilities		**(157,104)**	46,602	**(404,620)**	648,581
Decrease in acquired credit facilities	3	**—**	—	**—**	(373,608)
Debt issuance costs		**—**	(198)	**(25,023)**	(40,123)
Payments on lease obligations		**(2,738)**	(4,740)	**(13,088)**	(7,076)
Net proceeds from issuance of long-term notes	8	**—**	—	**780,936**	1,046,197
Redemption of long-term notes	8	**—**	—	**(580,913)**	—
Redemption of acquired long-term notes	3	**—**	—	**—**	(569,256)
Repurchase of common shares	10	**(84,573)**	(89,266)	**(168,468)**	(89,266)
Dividends declared	10	**(17,732)**	(19,138)	**(54,387)**	(19,138)
Change in non-cash working capital		**6,570**	(25,734)	**4,470**	(25,734)
Cash flows (used in) from financing activities		**(255,577)**	(92,474)	**(461,093)**	570,577
Investing activities					
Additions to exploration and evaluation assets	5	**—**	(40)	**—**	(1,271)
Additions to oil and gas properties	6	**(306,332)**	(409,151)	**(1,058,456)**	(812,250)
Additions to other plant and equipment		**(744)**	(1,279)	**(4,280)**	(2,300)
Corporate acquisition, net of cash acquired	3	**—**	—	**—**	(662,579)
Property acquisitions		**(1,042)**	(4,277)	**(39,794)**	(4,721)
Proceeds from dispositions		**1,436**	226	**4,156**	511
Change in non-cash working capital		**(2,359)**	67,224	**85,564**	109,189
Cash flows used in investing activities		**(309,041)**	(347,297)	**(1,012,810)**	(1,373,421)
Change in cash		**(14,576)**	4,262	**(34,504)**	18,435
Cash, beginning of period		**35,887**	19,637	**55,815**	5,464
Cash, end of period		**$ 21,311**	**$ 23,899**	**$ 21,311**	**$ 23,899**
Supplementary information					
Interest paid		**$ 38,581**	$ 45,941	**$ 143,597**	$ 83,945
Income taxes paid		**$ 1,730**	$ —	**$ 18,151**	$ 3,603

See accompanying notes to the condensed consolidated interim 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 and in Texas, United States. 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 condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2023 ("2023 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on October 31, 2024.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. 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 when otherwise indicated.

The audited 2023 annual consolidated financial statements of the Company are available through its filings on SEDAR+ at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov.

Estimation Uncertainty

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 reserves, the recoverable amount of long-lived assets or cash generating units, 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.

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 proposed standards that are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

Material Accounting Policies

Except as described below, the accounting policies, critical accounting judgments and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2023 annual consolidated financial statements.

New Accounting Standards Adopted

Effective January 1, 2024, Baytex adopted amendments to IAS 1 *Presentation of Financial Statements* which was issued by the IASB in January 2020. The amendments further clarify the requirements for the presentation of liabilities as current or non-current in the consolidated statements of financial position.

These amendments have not had a material impact on our consolidated financial statements.

3. BUSINESS COMBINATION

On June 20, 2023, Baytex closed the acquisition of Ranger Oil Corporation ("Ranger"), a publicly traded oil and gas exploration and production company with operations in the Eagle Ford. Baytex acquired all of the issued and outstanding common shares of Ranger and is treated as the acquirer for accounting purposes. The acquisition increases Baytex's Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford.

The acquisition was accounted for as a business combination with the net assets and liabilities recorded at fair value at the acquisition date. The total consideration of US$1.6 billion ($2.1 billion) consisted of $732.8 million of cash consideration and 311.4 million Baytex common shares valued at approximately $1.3 billion (based on the closing price of Baytex's common shares of $4.26 per share on the Toronto Stock Exchange on June 20, 2023). Under the terms of the agreement, Ranger shareholders received 7.49 Baytex shares plus US$13.31 cash for each share of Ranger common stock.

The fair value of oil and gas properties acquired was primarily based on estimated cash flows associated with proved and probable oil and gas reserves acquired and the discount rate. Factors that impact these reserves cash flows include forecasted production volumes, royalty obligations, operating and capital costs, taxes and commodity prices. The estimation of reserves cash flows involves the expertise of the independent qualified reserve evaluators. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets. The fair value of the acquired oil and gas properties were determined using a discount rate of 12.2%.

Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a market rate of interest of 9.0%.

The total consideration paid and estimates of the fair value of the assets and liabilities acquired as at the date of the acquisition are set forth in the table below. The purchase price equation was based on management's best estimate of the assets acquired and liabilities assumed. There were no measurement period adjustments recorded during the three and nine months ended September 30, 2024 and the purchase price is considered final.

	USD	CAD (1)
Consideration		
Cash	$ 553,150	$ 732,840
Common shares issued	1,001,196	1,326,435
Share-based compensation (2)	20,107	26,638
Total consideration	**$ 1,574,453**	**$ 2,085,913**
Fair value of net assets acquired		
Oil and gas properties	$ 2,337,173	$ 3,096,404
Working capital deficiency excluding bank debt and financial derivatives (3)	(120,565)	(159,731)
Financial derivatives	17,030	22,562
Lease assets	15,708	20,811
Lease obligations	(15,708)	(20,811)
Credit facilities	(282,000)	(373,608)
Long-term notes	(429,676)	(569,256)
Asset retirement obligations	(23,632)	(31,310)
Deferred income tax asset	76,123	100,852
Net assets acquired	**$ 1,574,453**	**$ 2,085,913**

(1) Exchange rate used to translate the U.S. denominated values above is the rate as at the closing date being CAD/USD 1.32485.

(2) Following closing of the transaction, holders of awards outstanding under Ranger's share based compensation plans are entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date while the remaining fair value of the share awards assumed by Baytex is being recognized over the remaining future service periods (note 11). Included in this balance is $21.3 million (US$16.1 million) of awards that were fully vested at close of the Ranger acquisition and $5.3 million (US$4.0 million) of cash-based awards included in share-based compensation liability.

(3) Includes $70.3 million (US$53.0 million) of cash. Trade receivables acquired is net of a provision for expected credit losses of approximately $0.3 million.

4. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the Eagle Ford in Texas; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 482,467**	$ 515,218	**$ 592,156**	$ 647,792	**$ —**	$ —	**$ 1,074,623**	$ 1,163,010
Royalties	**(71,351)**	(64,238)	**(152,449)**	(175,811)	**—**	—	**(223,800)**	(240,049)
	411,116	450,980	**439,707**	471,981	**—**	—	**850,823**	922,961
Expenses								
Operating	**87,373**	93,065	**79,746**	81,054	**—**	—	**167,119**	174,119
Transportation	**24,837**	16,075	**12,046**	11,908	**—**	—	**36,883**	27,983
Blending and other	**51,902**	49,830	**—**	—	**—**	—	**51,902**	49,830
General and administrative	**—**	—	**—**	—	**17,895**	20,536	**17,895**	20,536
Transaction costs	**—**	—	**—**	—	**—**	2,263	**—**	2,263
Exploration and evaluation	**82**	409	**—**	—	**—**	—	**82**	409
Depletion and depreciation	**123,742**	124,214	**229,003**	193,334	**3,639**	2,183	**356,384**	319,731
Share-based compensation	**—**	—	**—**	—	**2,305**	14,699	**2,305**	14,699
Financing and interest	**—**	—	**—**	—	**58,700**	68,065	**58,700**	68,065
Financial derivatives (gain) loss	**—**	—	**—**	—	**(22,927)**	28,641	**(22,927)**	28,641
Foreign exchange (gain) loss	**—**	—	**—**	—	**(24,552)**	42,682	**(24,552)**	42,682
Loss (gain) on dispositions and property swaps	**—**	(875)	**1,091**	—	**—**	—	**1,091**	(875)
Other income	**—**	—	**—**	—	**(9,107)**	(1,367)	**(9,107)**	(1,367)
	287,936	282,718	**321,886**	286,296	**25,953**	177,702	**635,775**	746,716
Net income (loss) before income taxes	**123,180**	168,262	**117,821**	185,685	**(25,953)**	(177,702)	**215,048**	176,245
Income tax expense (recovery)								
Current income tax (recovery) expense							**(3,748)**	808
Deferred income tax expense							**33,577**	48,007
							29,829	48,815
Net income (loss)	**$ 123,180**	$ 168,262	**$ 117,821**	$ 185,685	**$ (25,953)**	$ (177,702)	**$ 185,219**	$ 127,430
Additions to exploration and evaluation assets	**—**	40	**—**	—	**—**	—	**—**	40
Additions to oil and gas properties	**120,473**	107,013	**185,859**	302,138	**—**	—	**306,332**	409,151
Property acquisitions	**507**	4,277	**535**	—	**—**	—	**1,042**	4,277
Proceeds from dispositions	**236**	(226)	**(1,672)**	—	**—**	—	**(1,436)**	(226)

	Canada		U.S.		Corporate		Consolidated	
Nine Months Ended September 30	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,407,340**	$ 1,291,131	**$ 1,784,598**	$ 1,025,975	**$ —**	$ —	**$ 3,191,938**	$ 2,317,106
Royalties	**(200,809)**	(155,402)	**(472,602)**	(285,820)	**—**	—	**(673,411)**	(441,222)
	1,206,531	1,135,729	**1,311,996**	740,155	**—**	—	**2,518,527**	1,875,884
Expenses								
Operating	**257,191**	275,599	**251,068**	130,366	**—**	—	**508,259**	405,965
Transportation	**62,616**	46,320	**37,416**	13,242	**—**	—	**100,032**	59,562
Blending and other	**183,795**	162,506	**—**	—	**—**	—	**183,795**	162,506
General and administrative	**—**	—	**—**	—	**61,313**	47,510	**61,313**	47,510
Transaction costs	**—**	—	**—**	—	**1,539**	43,966	**1,539**	43,966
Exploration and evaluation	**749**	941	**—**	—	**—**	—	**749**	941
Depletion and depreciation	**358,603**	355,947	**685,295**	300,509	**9,724**	5,418	**1,053,622**	661,874
Share-based compensation	**—**	—	**—**	—	**17,393**	41,440	**17,393**	41,440
Financing and interest	**—**	—	**—**	—	**211,584**	126,287	**211,584**	126,287
Financial derivatives (gain) loss	**—**	—	**—**	—	**(4,598)**	17,054	**(4,598)**	17,054
Foreign exchange loss	**—**	—	**—**	—	**35,440**	30,680	**35,440**	30,680
(Gain) loss on dispositions and property swaps	**(1,055)**	(539)	**5,796**	—	**—**	—	**4,741**	(539)
Other income	**—**	(1,271)	**—**	—	**(7,011)**	(1,013)	**(7,011)**	(2,284)
	861,899	839,503	**979,575**	444,117	**325,384**	311,342	**2,166,858**	1,594,962
Net income (loss) before income taxes	**344,632**	296,226	**332,421**	296,038	**(325,384)**	(311,342)	**351,669**	280,922
Income tax expense (recovery)								
Current income tax expense							**4,407**	3,278
Deferred income tax expense (recovery)							**72,188**	(114,830)
							76,595	(111,552)
Net income (loss)	**$ 344,632**	$ 296,226	**$ 332,421**	$ 296,038	**$ (325,384)**	$ (311,342)	**$ 275,074**	$ 392,474
Additions to exploration and evaluation assets	**—**	1,271	**—**	—	**—**	—	**—**	1,271
Additions to oil and gas properties	**380,515**	386,791	**677,941**	425,459	**—**	—	**1,058,456**	812,250
Corporate acquisition, net of cash acquired	**—**	—	**—**	662,579	**—**	—	**—**	662,579
Property acquisitions	**36,584**	4,721	**3,210**	—	**—**	—	**39,794**	4,721
Proceeds from dispositions	**368**	(511)	**(4,524)**	—	**—**	—	**(4,156)**	(511)

	September 30, 2024	December 31, 2023
Canadian assets	**$ 2,404,850**	$ 2,289,083
U.S. assets	**5,155,202**	5,112,493
Corporate assets	**54,105**	59,355
Total consolidated assets	**$ 7,614,157**	$ 7,460,931

5. EXPLORATION AND EVALUATION ASSETS

	September 30, 2024	December 31, 2023
Balance, beginning of period	**$ 90,919**	$ 168,684
Property acquisitions	**35,887**	18,486
Divestitures	**(1,173)**	(2,965)
Property swaps	**(68)**	1,000
Exploration and evaluation expense	**(749)**	(8,896)
Transfer to oil and gas properties (note 6)	**(2,692)**	(83,530)
Foreign currency translation	**—**	(1,860)
Balance, end of period	**$ 122,124**	$ 90,919

At September 30, 2024 and December 31, 2023, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's cash generating units ("CGUs").

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2022	**$ 12,042,216**	**$ (7,421,450)**	**$ 4,620,766**
Capital expenditures	1,012,787	—	1,012,787
Corporate acquisition (note 3)	3,096,404	—	3,096,404
Property acquisitions	20,263	—	20,263
Transfers from exploration and evaluation assets (note 5)	83,530	—	83,530
Transfers from lease assets	7,611	—	7,611
Change in asset retirement obligations (note 9)	54,166	—	54,166
Divestitures	(660,920)	317,651	(343,269)
Property swaps	(2,975)	3,756	781
Impairment loss	—	(833,662)	(833,662)
Foreign currency translation	(127,065)	66,501	(60,564)
Depletion	—	(1,039,780)	(1,039,780)
Balance, December 31, 2023	**$ 15,526,017**	**$ (8,906,984)**	**$ 6,619,033**
Capital expenditures	1,058,456	—	1,058,456
Property acquisitions	4,185	—	4,185
Transfers from exploration and evaluation assets (note 5)	2,692	—	2,692
Transfers from lease assets	8,210	—	8,210
Change in asset retirement obligations (note 9)	27,343	—	27,343
Divestitures	(7,052)	1,313	(5,739)
Property swaps	997	682	1,679
Foreign currency translation	183,473	(79,098)	104,375
Depletion	—	(1,043,898)	(1,043,898)
Balance, September 30, 2024	**$ 16,804,321**	**$ (10,027,985)**	**$ 6,776,336**

At September 30, 2024, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

At December 31, 2023, the Company identified indicators of impairment for oil and gas properties in the legacy non-operated Eagle Ford CGU due to changes in reserves and in the Viking CGU due to changes in reserves and a loss recorded on disposition of an asset. The recoverable amounts for the two CGUs were not sufficient to support their carrying values which resulted in an impairment loss of $833.7 million recorded at December 31, 2023. The recoverable amount for each CGU is based on estimated cash flows associated with proved and probable oil and gas reserves from an independent reserve report prepared as at December 31, 2023 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%.

7. CREDIT FACILITIES

		September 30, 2024		December 31, 2023
Credit facilities - U.S. dollar denominated [(1)]	$	107,673	$	311,980
Credit facilities - Canadian dollar denominated		358,435		552,756
Credit facilities - principal [(2)]	$	466,108	$	864,736
Unamortized debt issuance costs		(16,992)		(15,987)
Credit facilities	$	449,116	$	848,749

(1) U.S. dollar denominated credit facilities balance was US$79.7 million as at September 30, 2024 (December 31, 2023 - US$236.3 million).

(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2023 to September 30, 2024 is the result of net repayments of $404.6 million, partially offset by an increase in the reported amount of U.S. denominated debt of $6.0 million due to foreign exchange.

On May 9, 2024, Baytex extended the maturity of the US$1.1 billion revolving credit facilities (the "Credit Facilities") from April 1, 2026 to May 9, 2028. There are no changes to the loan balances or financial covenants as a result of the amendment. Following the amendment, borrowings in Canadian funds previously based on the banker's acceptance rate have been replaced with borrowings based on the Canadian Overnight Repo Rate Average ("CORRA").

At September 30, 2024, Baytex had US$1.1 billion ($1.5 billion) of revolving credit facilities that mature on May 9, 2028. The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

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 bank's prime lending rate, CORRA rates or secured overnight financing rates ("SOFR"), plus applicable margins. Advances under the Baytex Energy USA, Inc. Credit Facilities can be drawn in U.S. funds and bear interest at the bank's prime lending rate or SOFR, plus applicable margins.

The weighted average interest rate on the Credit Facilities was 7.9% for the nine months ended September 30, 2024 (7.3% for nine months ended September 30, 2023).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at September 30, 2024.

Covenant Description	Position as at September 30, 2024	Covenant
Senior Secured Debt [(1)] to Bank EBITDA [(2)] (Maximum Ratio)	0.2:1.0	3.5:1.0
Interest Coverage [(3)] (Minimum Ratio)	10.5:1.0	3.5:1.0
Total Debt [(4)] to Bank EBITDA [(2)] (Maximum Ratio)	1.0:1.0	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 September 30, 2024, the Company's Senior Secured Debt totaled $470.8 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 acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2024 was $2.2 billion.

(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 expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended September 30, 2024 was $212.4 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 September 30, 2024, the Company's Total Debt totaled $2.3 billion of principal amounts outstanding.

At September 30, 2024, Baytex had $5.7 million of outstanding letters of credit (December 31, 2023 - $5.6 million outstanding) under the Credit Facilities.

8. LONG-TERM NOTES

	September 30, 2024	December 31, 2023
8.75% notes due April 1, 2027 (1)	**$ —**	$ 541,114
8.50% notes due April 30, 2030 (2)	**1,080,360**	1,056,361
7.375% notes due March 15, 2032 (3)	**776,509**	—
Total long-term notes - principal (4)	**$ 1,856,869**	$ 1,597,475
Unamortized debt issuance costs	**(46,168)**	(35,114)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,810,701**	$ 1,562,361

(1) The 8.75% notes were fully repaid on April 1, 2024. The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million as at December 31, 2023.

(2) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million as at September 30, 2024 (December 31, 2023 - US$800.0 million).

(3) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$575.0 million as at September 30, 2024 (December 31, 2023 - nil).

(4) The increase in the principal amount of long-term notes outstanding from December 31, 2023 to September 30, 2024 is the result of the issuance of the 7.375% notes for $780.9 million and changes in the reported amount of U.S. denominated debt of $35.0 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding. This was partially offset by the repayment of the 8.75% notes for $556.6 million.

On April 1, 2024, Baytex closed a private offering of the US$575 million aggregate principal amount of senior unsecured notes due 2032 ("7.375% Senior Notes"). 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. Proceeds from the 7.375% Senior Notes were used to redeem the remaining US$409.8 million aggregate principal amount of the outstanding 8.75% Senior Notes at 104.375% of par value, pay the related fees and expenses associated with the offering, and repay a portion of the debt outstanding on our Credit Facilities. During Q2 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 and restricted payments.

9. ASSET RETIREMENT OBLIGATIONS

	September 30, 2024	December 31, 2023
Balance, beginning of period	**$ 623,399**	$ 588,923
Liabilities incurred [1]	**20,340**	24,185
Liabilities settled	**(22,344)**	(26,416)
Liabilities assumed from corporate acquisition (note 3)	**—**	31,310
Liabilities acquired from property acquisitions	**310**	11
Liabilities divested	**(2,098)**	(43,153)
Property swaps	**(728)**	76
Accretion (note 15)	**15,910**	20,406
Government grants [2]	**—**	(1,271)
Change in estimate [1]	**12,421**	17,067
Changes in discount and inflation rates [1][3]	**(5,418)**	12,914
Foreign currency translation	**2,059**	(653)
Balance, end of period	**$ 643,851**	$ 623,399
Less current portion of asset retirement obligations	**17,512**	20,448
Non-current portion of asset retirement obligations	**$ 626,339**	$ 602,951

(1) The total of these items reflects the total change in asset retirement obligations of $27.3 million per Note 6 - Oil and Gas Properties ($54.2 million increase in 2023).

(2) Certain government grants were provided by the Government of Alberta and the Government of Saskatchewan under programs that were completed during the year ended December 31, 2023. During the nine months ended September 30, 2024, no amounts have been recognized under these programs ($1.3 million for the year ended December 31, 2023).

(3) The discount and inflation rates used to calculate the liability for our Canadian operations at September 30, 2024 were 3.1% and 1.6% respectively (December 31, 2023 - 3.0% and 1.6%). The discount and inflation rates used to calculate the liability for our U.S. operations at September 30, 2024 were 4.1% and 2.2%, respectively (December 31, 2023 - 4.0% and 2.1%).

10. 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 September 30, 2024, 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, 2022	**544,930**	**$ 5,499,664**
Issued on corporate acquisition	311,370	1,326,435
Vesting of share awards	5,892	26,229
Common shares repurchased and cancelled	(40,511)	(325,039)
Balance, December 31, 2023	**821,681**	**$ 6,527,289**
Vesting of share awards	272	1,167
Common shares repurchased and cancelled	(34,625)	(280,172)
Balance, September 30, 2024	**787,328**	**$ 6,248,284**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 26, 2024, Baytex announced that the Toronto Stock Exchange ("TSX") accepted the renewal of the NCIB under which Baytex is permitted to purchase for cancellation up to 70.1 million common shares over the 12-month period commencing July 2, 2024. The number of shares authorized for repurchase represented 10% of the Company's public float, as defined by the TSX, as at June 18, 2024. On June 18, 2024 Baytex had 808.0 million common shares outstanding.

During the nine months ended September 30, 2024, Baytex recorded $168.5 million related to common share repurchases, which includes $165.2 million of consideration paid for the repurchase and cancellation of common shares as well as $3.3 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 nine months ended September 30, 2024, Baytex repurchased and cancelled 34.6 million common shares at an average price of $4.77 per share for total consideration of $165.2 million. During 2023, Baytex repurchased and cancelled 40.5 million common shares at an average price of $5.48 per share for total consideration of $221.9 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.

Effective January 1, 2024, the Government of Canada introduced a 2% federal tax on equity repurchases. During the nine months ended September 30, 2024, Baytex recorded a $3.3 million liability, charged to shareholders' capital, related to the federal tax on equity repurchases.

Dividends

The following dividends were declared by Baytex during the nine months ended September 30, 2024.

Record Date	Payable Date	Per Share Amount	Dividend Amount
March 15, 2024	April 1, 2024	$ 0.0225	$ 18,494
June 14, 2024	July 2, 2024	0.0225	18,161
September 16, 2024	October 1, 2024	0.0225	17,732
Total dividends declared			**$ 54,387**

On October 31, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 2, 2025 for shareholders of record on December 13, 2024.

11. SHARE-BASED COMPENSATION PLAN

For the three and nine months ended September 30, 2024 the Company recorded share-based compensation expense of $2.3 million and $17.4 million respectively ($14.7 million and $41.4 million for the three and nine months ended September 30, 2023) which is related to cash-settled awards.

The Company's closing share price on the Toronto Stock Exchange on September 30, 2024 was $4.04 (December 31, 2023 - $4.38 and September 30, 2023 - $5.99).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	Director Share Units	Total
Total, December 31, 2022	**762**	**4,796**	**5,109**	**967**	**11,634**
Granted	41	2,641	2,607	278	5,567
Assumed on corporate acquisition [1]	10,789	—	—	—	10,789
Vested	(9,302)	(3,767)	(2,715)	—	(15,784)
Forfeited	(11)	(315)	(518)	—	(844)
Total, December 31, 2023	**2,279**	**3,355**	**4,483**	**1,245**	**11,362**
Granted	8	2,343	3,561	245	6,157
Added by performance factor	—	524	—	—	524
Vested	(1,457)	(2,443)	(2,541)	(162)	(6,603)
Forfeited	—	(20)	(106)	—	(126)
Total, September 30, 2024	**830**	**3,759**	**5,397**	**1,328**	**11,314**

(1) Following the closing of the transaction, holders of awards outstanding under Ranger's Share Award Plan were entitled to Baytex common shares rather than Ranger common shares with an adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date (note 3) while the remaining fair value of the share awards assumed by Baytex is recognized over the remaining future service periods.

Share Award Incentive Plan

Baytex has a Share Award Incentive Plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex 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 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 Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

In 2023, Baytex became the successor to Ranger's Share Award Plan (note 3). Awards outstanding as at the closing day of the acquisition were converted to restricted awards that will be settled in shares of Baytex or with cash, with the quantity outstanding adjusted based on the exchange ratio for the business combination with Ranger.

The weighted average fair value of share awards granted during the nine months ended September 30, 2024 was $4.28 per restricted and performance award ($5.44 for the nine months ended September 30, 2023).

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. 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 nine months ended September 30, 2024 was $4.29 per incentive award ($5.41 for the nine months ended September 30, 2023).

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 nine months ended September 30, 2024 was $4.57 per DSU award ($5.15 for the nine months ended September 30, 2023).

12. NET INCOME PER SHARE

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 period.

	Three Months Ended September 30					
	2024			2023		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 185,219**	**796,064**	**$ 0.23**	$ 127,430	855,300	$ 0.15
Dilutive effect of share awards	**—**	**4,153**	**—**	—	5,272	—
Net income - diluted	**$ 185,219**	**800,217**	**$ 0.23**	$ 127,430	860,572	$ 0.15

	Nine Months Ended September 30					
	2024			2023		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	**Net income**	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 275,074**	**810,589**	**$ 0.34**	$ 392,474	662,379	$ 0.59
Dilutive effect of share awards	**—**	**3,762**	**—**	—	3,815	—
Net income - diluted	**$ 275,074**	**814,351**	**$ 0.34**	$ 392,474	666,194	$ 0.59

For the three and nine months ended September 30, 2024 and September 30, 2023, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

13. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

	Three Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 122,452**	**$ 525,135**	**$ 647,587**	$ 173,475	$ 583,304	$ 756,779
Heavy oil	**350,859**	**—**	**350,859**	323,272	—	323,272
NGL	**6,067**	**44,034**	**50,101**	5,945	41,027	46,972
Natural gas sales	**3,089**	**22,987**	**26,076**	12,526	23,461	35,987
Total petroleum and natural gas sales	**$ 482,467**	**$ 592,156**	**$ 1,074,623**	$ 515,218	$ 647,792	$ 1,163,010

	Nine Months Ended September 30					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 321,704**	**$ 1,589,648**	**$ 1,911,352**	$ 444,894	$ 909,159	$ 1,354,053
Heavy oil	**1,050,743**	**—**	**1,050,743**	791,806	—	791,806
NGL	**17,579**	**127,963**	**145,542**	15,777	73,192	88,969
Natural gas sales	**17,314**	**66,987**	**84,301**	38,654	43,624	82,278
Total petroleum and natural gas sales	**$ 1,407,340**	**$ 1,784,598**	**$ 3,191,938**	$ 1,291,131	$ 1,025,975	$ 2,317,106

Included in accounts receivable at September 30, 2024 is $311.7 million of accrued receivables related to delivered volumes (December 31, 2023 - $271.1 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2024	2023
Net income before income taxes	**$ 351,669**	$ 280,922
Expected income taxes at the statutory rate of 24.38% (2023 – 24.64%) (1)	**85,737**	69,219
Change in income taxes resulting from:		
Effect of foreign exchange	**4,269**	2,817
Effect of change in income tax rates	**—**	(427)
Effect of rate adjustments for foreign jurisdictions	**(6,333)**	(7,230)
Effect of change in deferred tax benefit not recognized (2)	**(22,087)**	3,213
Effect of internal debt restructuring (3)	**—**	(186,319)
Repatriation and related taxes	**10,863**	2,682
Adjustments, assessments and other	**4,146**	4,493
Income tax expense (recovery)	**$ 76,595**	$ (111,552)

(1) The expected income tax rate decreased from 2023 due to changes in the provincial apportionment of Canadian income.

(2) A deferred tax asset of $16.4 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2023 - $40.4 million). These deferred income tax assets relate to capital losses of $137.0 million and non-capital losses of $1.3 million.

(3) A deferred income tax asset was recognized in the nine months ended September 30, 2023 after the closing of the Ranger acquisition due to effects of the transaction structuring.

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 Q4/2023, 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 reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $208.6 million as at the date of reassessments 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. If, after exhausting available appeals, the deduction of 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.

15. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Interest on Credit Facilities	**$ 12,343**	$ 21,671	**$ 46,271**	$ 35,422
Interest on long-term notes	**37,426**	34,664	**109,760**	67,323
Interest on lease obligations	**340**	160	**1,304**	380
Cash interest	**$ 50,109**	$ 56,495	**$ 157,335**	$ 103,125
Amortization of debt issue costs	**3,067**	6,539	**13,989**	8,910
Accretion on asset retirement obligations (note 9)	**5,524**	5,031	**15,910**	14,252
Early redemption expense (note 8)	**—**	—	**24,350**	—
Financing and interest	**$ 58,700**	$ 68,065	**$ 211,584**	$ 126,287

16. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Unrealized foreign exchange (gain) loss	**$ (24,401)**	$ 42,392	**$ 33,506**	$ 29,299
Realized foreign exchange (gain) loss	**(151)**	290	**1,934**	1,381
Foreign exchange (gain) loss	**$ (24,552)**	$ 42,682	**$ 35,440**	$ 30,680

17. 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 trade receivables and trade payables 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 condensed consolidated statements of financial position are classified into the following categories:

	September 30, 2024		December 31, 2023		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
Fair value through profit and loss					
Financial derivatives	**$ 24,310**	**$ 24,310**	$ 23,274	$ 23,274	Level 2
Total	**$ 24,310**	**$ 24,310**	$ 23,274	$ 23,274	
Amortized cost					
Cash	**$ 21,311**	**$ 21,311**	$ 55,815	$ 55,815	—
Trade receivables	**375,942**	**375,942**	339,405	339,405	—
Total	**$ 397,253**	**$ 397,253**	$ 395,220	$ 395,220	
Financial Liabilities					
Amortized cost					
Trade payables	**$ (584,696)**	**$ (584,696)**	$ (477,295)	$ (477,295)	—
Dividends payable	**(17,732)**	**(17,732)**	(18,381)	(18,381)	—
Credit Facilities (1)	**(449,116)**	**(466,108)**	(848,749)	(864,736)	—
Long-term notes	**(1,810,701)**	**(1,896,351)**	(1,562,361)	(1,653,118)	Level 1
Total	**$ (2,862,245)**	**$ (2,964,887)**	$ (2,906,786)	$ (3,013,530)	

(1) The difference in the carrying value and fair value of the credit facilities is due to unamortized debt issuance costs. Refer to Note 7.

There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 2024 and 2023.

Foreign Currency Risk

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	
	September 30, 2024	December 31, 2023	**September 30, 2024**	December 31, 2023
U.S. dollar denominated	**US$22,356**	US$17,923	**US$1,405,247**	US$1,249,725

Commodity Price Risk

Financial Derivative Contracts

As at October 31, 2024, Baytex had the following commodity financial derivative contracts.

	Remaining Period	Volume	Price/Unit [(1)]	Index
Oil				
Basis differential	Oct 2024 to Dec 2024	15,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.31/bbl	WCS
Basis differential	Oct 2024 to Dec 2024	6,000 bbl/d	WTI less US$13.58/bbl	WCS
Basis differential	Oct 2024 to Dec 2024	6,250 bbl/d	WTI less US$2.87/bbl	MSW
Basis differential	Jan 2025 to Dec 2025	2,000 bbl/d	WTI less US$2.75/bbl	MSW
Basis differential	Jan 2025 to Jun 2025	3,000 bbl/d	WTI less US$13.50/bbl	WCS
Basis differential [(2)]	Jul 2025 to Dec 2025	2,500 bbl/d	WTI less US$13.50/bbl	WCS
Basis differential [(2)]	Jan 2025 to Dec 2025	9,500 bbl/d	WTI less US$13.18/bbl	WCS
Collar	Oct 2024 to Dec 2024	12,500 bbl/d	US$60.00/US$100.00	WTI
Collar	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	Oct 2024 to Dec 2024	1,500 bbl/d	US$60.00/US$90.35	WTI
Collar	Oct 2024 to Dec 2024	1,000 bbl/d	US$60.00/US$90.00	WTI
Collar	Oct 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$85.00	WTI
Collar	Oct 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$84.60	WTI
Collar	Oct 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$84.15	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$87.10	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$85.75	WTI
Collar	Jan 2025 to Mar 2025	5,000 bbl/d	US$60.00/US$88.70	WTI
Collar	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.20	WTI
Collar	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.05	WTI
Collar	Jan 2025 to Mar 2025	7,500 bbl/d	US$60.00/US$90.00	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$94.25	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$93.90	WTI
Collar	Jan 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$91.95	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Collar	Jan 2025 to Jun 2025	3,000 bbl/d	US$60.00/US$89.55	WTI
Collar	Apr 2025 to Jun 2025	2,000 bbl/d	US$60.00/US$88.17	WTI
Collar	Apr 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$90.50	WTI
Collar	Apr 2025 to Jun 2025	3,000 bbl/d	US$60.00/US$90.60	WTI
Collar [(2)]	Jan 2025 to Dec 2025	4,500 bbl/d	US$60.00/US$80.00	WTI
Collar [(2)]	Jul 2025 to Dec 2025	27,500 bbl/d	US$60.00/US$80.00	WTI
Collar [(2)]	Oct 2025 to Dec 2025	3,500 bbl/d	US$60.00/US$80.00	WTI
Collar [(2)]	Apr 2025 to Sep 2025	8,000 bbl/d	US$60.00/US$80.00	WTI

(1) Based on the weighted average price per unit for the period.
(2) Contract entered subsequent to September 30, 2024.

	Remaining Period	Volume	Price/Unit [1]	Index
Natural Gas				
Collar	Oct 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.185	NYMEX
Collar	Oct 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Oct 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Oct 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Oct 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar	Jan 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.03	NYMEX
Collar	Jan 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.08	NYMEX
Collar	Jan 2025 to Dec 2025	3,000 mmbtu/d	US$3.25/US$4.135	NYMEX
Collar	Jan 2025 to Dec 2025	5,500 mmbtu/d	US$3.25/US$4.14	NYMEX
Collar	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX
Collar	Jan 2025 to Dec 2025	3,000 mmbtu/d	US$3.00/US$4.85	NYMEX
Collar	Jan 2025 to Dec 2025	8,000 mmbtu/d	US$3.00/US$4.855	NYMEX
Collar	Jan 2026 to Dec 2026	11,000 mmbtu/d	US$3.25/US$5.02	NYMEX
AECO basis differential	Oct 2024 to Dec 2024	5,000 mmbtu/d	NYMEX less US$1.23/mmbtu	NYMEX
AECO basis differential	Jan 2025 to Mar 2025	5,000 mmbtu/d	NYMEX less US$1.27/mmbtu	NYMEX
AECO basis differential	Apr 2025 to Jun 2025	5,000 mmbtu/d	NYMEX less US$1.19/mmbtu	NYMEX
Collar [2]	Jan 2025 to Jun 2025	3,000 mmbtu/d	US$3.00/US$4.05	NYMEX
Collar [2]	Jul 2025 to Dec 2025	9,000 mmbtu/d	US$3.00/US$4.05	NYMEX
Collar [2]	Jan 2026 to Dec 2026	10,000 mmbtu/d	US$3.25/US$4.25	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contract entered subsequent to September 30, 2024.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Realized financial derivatives gain	**$ (331)**	$ (2,055)	**$ (3,562)**	$ (23,835)
Unrealized financial derivatives (gain) loss	**(22,596)**	30,696	**(1,036)**	40,889
Financial derivatives (gain) loss	**$ (22,927)**	$ 28,641	**$ (4,598)**	$ 17,054

18. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At September 30, 2024, 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, 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 Debt

The Company uses net debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net 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 debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

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

	September 30, 2024	December 31, 2023
Credit Facilities	**$ 449,116**	$ 848,749
Unamortized debt issuance costs - Credit Facilities (note 7)	**16,992**	15,987
Long-term notes	**1,810,701**	1,562,361
Unamortized debt issuance costs - Long-term notes (note 8)	**46,168**	35,114
Trade payables	**584,696**	477,295
Share-based compensation liability	**23,962**	35,732
Dividends payable	**17,732**	18,381
Other long-term liabilities	**19,582**	19,147
Cash	**(21,311)**	(55,815)
Trade receivables	**(375,942)**	(339,405)
Prepaids and other assets	**(78,427)**	(83,259)
Net Debt	**$ 2,493,269**	$ 2,534,287

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 September 30		Nine Months Ended September 30	
	2024	2023	**2024**	2023
Cash flows from operating activities	**$ 550,042**	$ 444,033	**$ 1,439,399**	$ 821,279
Change in non-cash working capital	**(20,813)**	126,075	**31,350**	205,924
Asset retirement obligations settled	**8,718**	9,252	**22,344**	18,770
Transaction costs	**—**	2,263	**1,539**	43,966
Cash premiums on derivatives	**—**	—	**—**	2,263
Adjusted Funds Flow	**$ 537,947**	$ 581,623	**$ 1,494,632**	$ 1,092,202

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman of the Board

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Director

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Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Angela S. Lekatsas [1,4]
Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [3,4]
Director

Jeffrey E. Wojahn [2,4]
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
President and
Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Chad E. Lundberg
Chief Operating 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

Taylor J. Young
Vice President and General Manager,
Eagle Ford Operations

Chris M.P. Lessoway
Vice President,
Finance and Treasurer

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Odyssey Trust Company

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New York Stock Exchange
Toronto Stock Exchange
Symbol: **BTE**

Design: ARTHUR / HUNTER
Printing: Merrill Corporation

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