Baytex Delivers Solid Second Quarter 2025 Results with Record Pembina Duvernay Well Performance and Continued Debt Reduction

Calgary, Alberta--(Newsfile Corp. - July 31, 2025) - Baytex Energy Corp. (TSX: BTE) (NYSE: BTE) ("Baytex" or the "Company") reports its operating and financial results for the three and six months ended June 30, 2025 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex delivered solid operational and financial results in the second quarter, with top-performing wells in the Pembina Duvernay, setting the highest average 30-day peak oil rates in the West Shale Basin," said Eric T. Greager, President and Chief Executive Officer. "Combined with strong results across heavy oil operations and the Eagle Ford, including continued success with refracs, these results demonstrate the resource potential and value creation opportunities within our portfolio. We remain focused on disciplined capital allocation, prioritizing free cash flow and debt reduction while capitalizing on the most compelling opportunities from our high-quality assets."

Second Quarter 2025 Highlights

- Achieved record Pembina Duvernay well performance with the first pad (3 wells) delivering average peak 30-day initial rates of 1,865 boe/d per well (89% oil and NGL).
- Successfully completed two Lower Eagle Ford refracs, extending inventory duration and improving capital efficiencies.
- Delivered production of 148,095 boe/d (84% oil and NGL), which represents a 2% increase in production per basic share compared to Q2/2024.
- Increased heavy oil production 7% over Q1/2025, driven by strong Peavine, Peace River and Lloydminster performance.
- Reported cash flows from operating activities of $354 million ($0.46 per basic share).
- Generated net income of $152 million ($0.20 per basic share).
- Delivered adjusted funds flow(1) of $367 million ($0.48 per basic share).
- Repurchased and cancelled US$41 million principal amount of 8.5% long-term notes.
- Reduced net debt(1) by 4% ($96 million) and maintained balance sheet strength with a total debt(2) to Bank EBITDA(2) ratio of 1.1x.

2025 Outlook

In light of the current commodity price environment, we are targeting annual production of approximately 148,000 boe/d with full-year exploration and development expenditures of approximately $1.2 billion. Production is expected to average approximately 150,000 boe/d in the second half of 2025.

Based on forward strip pricing(3), we expect to generate approximately $400 million of free cash flow(4) in 2025, with the majority weighted to the second half of the year given our production and capital spending profile. We plan to allocate 100% of free cash flow to debt repayment after funding quarterly dividend payments, targeting net debt of approximately $2 billion by year-end.

We remain committed to disciplined capital allocation, prioritizing free cash flow and strengthening our balance sheet. We will continue to monitor market conditions and execute a prudent approach to shareholder returns, which has historically included a combination of share buybacks and quarterly dividend payments.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Ratio is calculated as total debt on June 30, 2025 divided by EBITDA for the twelve months ended June 30, 2025. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(3) 2025 full-year pricing assumptions: WTI - US$67.75/bbl; WCS differential - US$11.50/bbl; NYMEX Gas - US$3.60/MMbtu; Exchange Rate (CAD/USD) - 1.39.
(4) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("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.

	Three Months Ended			Six Months Ended	
	June 30, 2025	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 886,579**	$ 999,130	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Adjusted funds flow (1)	**366,919**	463,870	532,839	**830,789**	956,685
Per share - basic	**0.48**	0.60	0.65	**1.08**	1.17
Per share - diluted	**0.48**	0.60	0.65	**1.07**	1.16
Free cash flow (2)	**3,188**	52,529	180,673	**55,717**	180,585
Per share - basic	**-**	0.07	0.22	**0.07**	0.22
Per share - diluted	**-**	0.07	0.22	**0.07**	0.22
Cash flows from operating activities	**354,312**	431,317	505,584	**785,629**	889,357
Per share - basic	**0.46**	0.56	0.62	**1.02**	1.09

Per share - diluted	**0.46**	0.56	0.62	**1.02**	1.08
Net income	**151,549**	69,591	103,898	**221,140**	89,855
Per share - basic	**0.20**	0.09	0.13	**0.29**	0.11
Per share - diluted	**0.20**	0.09	0.13	**0.29**	0.11
Dividends declared	**17,304**	17,334	18,161	**34,593**	36,655
Per share	**0.0225**	0.0225	0.0225	**0.0450**	0.0450
Capital Expenditures					
Exploration and development expenditures	**$ 356,532**	$ 405,097	$ 339,573	**$ 761,629**	$ 752,124
Acquisitions and divestitures	**468**	(1,009)	654	**(541)**	36,032
Total oil and natural gas capital expenditures	**$ 357,000**	$ 404,088	$ 340,227	**$ 761,088**	$ 788,156
Net Debt					
Credit facilities	**$ 333,516**	$ 250,284	$ 625,976	**$ 333,516**	$ 625,976
Long-term notes	**1,817,707**	1,977,044	1,881,894	**1,817,707**	1,881,894
Total debt (3)	**2,151,223**	2,227,328	2,507,870	**2,151,223**	2,507,870
Working capital deficiency (2)	**142,717**	162,922	131,144	**142,717**	131,144
Net debt (1)	**$ 2,293,940**	$ 2,390,250	$ 2,639,014	**$ 2,293,940**	$ 2,639,014
Shares Outstanding - basic (thousands)					
Weighted average	**768,717**	771,443	814,151	**770,072**	817,931
End of period	**768,317**	770,039	804,977	**768,317**	804,977
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 63.74**	$ 71.42	$ 80.57	**$ 67.58**	$ 78.77
MEH oil (US$/bbl)	**65.56**	73.37	83.10	**69.47**	81.03
MEH oil differential to WTI (US$/bbl)	**1.82**	1.95	2.53	**1.89**	2.26
Edmonton par ($/bbl)	**84.15**	95.27	105.30	**89.71**	98.73
Edmonton par differential to WTI (US$/bbl)	**(2.94)**	(5.03)	(3.62)	**(3.93)**	(6.10)
WCS heavy oil ($/bbl)	**74.10**	84.33	91.72	**79.15**	84.68
WCS differential to WTI (US$/bbl)	**(10.20)**	(12.65)	(13.55)	**(11.43)**	(16.44)
Natural gas					
NYMEX (US$/MMbtu)	**$ 3.44**	$ 3.65	$ 1.89	**$ 3.55**	$ 2.07
AECO ($/Mcf)	**2.07**	2.02	1.44	**2.05**	1.74
CAD/USD average exchange rate	**1.3840**	1.4350	1.3684	**1.4095**	1.3586

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			Six Months Ended	
	June 30, 2025	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**62,108**	62,335	67,031	**62,221**	66,534
Heavy oil (bbl/d)	**42,959**	40,192	43,703	**41,583**	42,131
NGL (bbl/d)	**19,948**	19,046	20,167	**19,499**	19,733
Total liquids (bbl/d)	**125,015**	121,573	130,901	**123,303**	128,398
Natural gas (Mcf/d)	**138,482**	135,731	139,764	**137,114**	144,059
Oil equivalent (boe/d @ 6:1) (1)	**148,095**	144,194	154,194	**146,156**	152,407
Adjusted Funds Flow (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 824,198**	$ 926,310	$ 1,065,438	**$ 1,750,508**	$ 1,985,422
Royalties	**(177,390)**	(207,937)	(240,440)	**(385,327)**	(449,611)
Operating expense	**(161,020)**	(147,703)	(167,705)	**(308,723)**	(341,140)
Transportation expense	**(32,907)**	(30,512)	(33,314)	**(63,419)**	(63,149)
Operating netback (2)	**$ 452,881**	$ 540,158	$ 623,979	**$ 993,039**	**$ 1,131,522**
General and administrative expense	**(22,220)**	(25,606)	(21,006)	**(47,826)**	(43,418)
Cash interest	**(44,875)**	(46,787)	(53,946)	**(91,662)**	(107,226)
Realized financial derivatives (loss) gain	**(11,874)**	(194)	(2,257)	**(12,068)**	3,231
Other (3)	**(6,993)**	(3,701)	(13,931)	**(10,694)**	(27,424)
Adjusted funds flow (4)	**$ 366,919**	$ 463,870	$ 532,839	**$ 830,789**	**$ 956,685**
Adjusted Funds Flow (per boe)					
Total sales, net of blending and other expense (2)	**$ 61.16**	$ 71.38	$ 75.93	**$ 66.17**	$ 71.58
Royalties (5)	**(13.16)**	(16.02)	(17.14)	**(14.57)**	(16.21)
Operating expense (5)	**(11.95)**	(11.38)	(11.95)	**(11.67)**	(12.30)
Transportation expense (5)	**(2.44)**	(2.35)	(2.37)	**(2.40)**	(2.28)
Operating netback (2)	**$ 33.61**	$ 41.63	$ 44.47	**$ 37.53**	**$ 40.79**
General and administrative expense (5)	**(1.65)**	(1.97)	(1.50)	**(1.81)**	(1.57)
Cash interest (5)	**(3.33)**	(3.61)	(3.84)	**(3.46)**	(3.87)
Realized financial derivatives (loss) gain (5)	**(0.88)**	(0.01)	(0.16)	**(0.46)**	0.12
Other (3)(5)	**(0.52)**	(0.30)	(1.00)	**(0.40)**	(0.98)
Adjusted funds flow	**$ 27.23**	$ 35.74	$ 37.97	**$ 31.40**	**$ 34.49**

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 and cash share-based compensation. Refer to the Q2/2025 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 expense, transportation expense, general and administrative expense, cash interest, realized financial derivatives gain or loss, or other, divided by barrels of oil equivalent production volume for the applicable period.

Financial Results

During the second quarter, we delivered operating and financial results in line with our full-year plan. Adjusted funds flow[(1)] was $367 million ($0.48 per basic share) and net income was $152 million ($0.20 per basic share).

We generated free cash flow[(2)] of $3 million and returned $21 million to shareholders through share repurchases of $4 million (1.7 million shares at an average price of $2.36) and a quarterly dividend payment of $17 million.

Net debt[(1)] decreased 4% ($96 million) to $2.3 billion, driven by unrealized foreign exchange gains from a strengthening Canadian dollar on our U.S. dollar-denominated debt. During the quarter, we repurchased and cancelled US$41 million principal amount of the 8.5% long-term notes below par.

We maintain strong financial flexibility with US$1.1 billion in credit facilities that mature in June 2029 and are less than 25% drawn, positioning us well across various commodity price cycles.

Operations

Production averaged 148,095 boe/d (84% oil and NGL) in the second quarter, representing a 2% increase in production per basic share compared to Q2/2024. Consistent with our full-year plan, exploration and development expenditures for Q2/2025 totaled $357 million and we brought 74 (66.5 net) wells onstream.

Inventory Extension Through Successful Eagle Ford Refracs

Eagle Ford production averaged 83,928 boe/d (81% oil and NGL), up 3% from Q1/2025. We brought onstream 14.9 net wells while realizing an approximate 11% improvement in operated drilling and completion costs per completed lateral foot compared to 2024. We also completed two successful refracs that are delivering initial rates comparable to our broader development program with improved capital efficiencies and returns.

The two refracs (Moulton A5H and Renee Unit 2H) were brought onstream in April and May with average completed lateral lengths of 1,648 meters (5,406 feet) and generated average 30-day peak production rates of 963 boe/d per well (734 bbl/d of crude oil, 124 bbl/d of NGLs, 631 Mcf/d of natural gas).

The refrac program extends inventory duration - we have identified approximately 300 refrac opportunities across our acreage and anticipate an expanded program in 2026.

Record Pembina Duvernay Well Results Demonstrate Asset Potential

Production from our Canadian light oil business averaged 16,349 boe/d (81% oil and NGL), relatively unchanged from Q1/2025. The Pembina Duvernay represents our largest growth asset and accounts for 40% of Canadian light oil production, with the remaining 60% from Viking operations.

The first Pembina Duvernay pad (07-01, 3 wells) from our 2025 program was brought onstream in May with average lateral lengths of 3,800 meters (12,500 feet) and generated average 30-day peak production rates of 1,865 boe/d per well (1,239 bbl/d of crude oil, 422 bbl/d of NGLs, 1,224 Mcf/d of natural gas). The second pad (08-08, 3 wells) came onstream through early July with similar lateral lengths, and over the last 26 days has averaged 1,264 boe/d per well (709 bbl/d of crude oil, 352 bbl/d of NGLs, 1,220 Mcf/d of natural gas. The third pad (10-31, 3 wells) is expected onstream in September.

The first two pads have exceeded initial rate expectations with the first pad delivering the highest peak oil rates to-date in the West Shale Basin. These results demonstrate our continued advancement in drilling and completion performance and facility enhancements. Strong production performance, combined with an approximate 12% improvement in drilling and completion costs per completed lateral foot compared to 2024 has significantly improved well economics.

We have assembled 140 net sections of highly prospective lands and identified approximately 200 drilling locations. As we transition to full commercialization over the next two years, we plan to implement a one-rig drilling program with 18 to 20 wells per year. At this development pace, we expect production to increase to 20,000-25,000 boe/d by 2029-2030, up from 6,665 boe/d in the second quarter.

(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.

Organic Heavy Oil Growth

Heavy oil production averaged 44,895 boe/d (96% oil and NGL), up 7% from Q1/2025. Strong operating results reflect continued performance at Peavine, Peace River, and across the broader Mannville group in Lloydminster. During the quarter, we brought onstream 43 net wells: 15 Clearwater wells at Peavine, 4 wells at Peace River, and 24 wells at Lloydminster.

Our heavy oil operations deliver the strongest economic returns across the portfolio, supported by our extensive acreage position, capital-efficient development, and the continued strength in Western Canadian Select pricing.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share, payable October 1, 2025 to shareholders of record on September 15, 2025.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2025 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MT (11:00 a.m. ET)

Baytex will host a conference call tomorrow, August 1, 2025, starting at 9:00am MT (11:00am ET). To participate, please dial toll free in North America 1-833-821-2925 or international 1-647-846-2449. Alternatively, to listen to the conference call online, please enter https://event.choruscall.com/mediaframe/webcast.html?webcastid=mLhH9WQY in your web browser. To register, visit our website at https://www.baytexenergy.com/investors/events-presentations.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

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: we are focused on disciplined capital allocation, prioritizing free cash flow, debt reduction and maximizing shareholder returns; for 2025: our guidance for exploration and development expenditures and production and the amount of free cash flow we expect to generate and its expected allocation; our targeted net debt at year-end 2025; the opportunity for refracs on our Eagle Ford acreage and the expected 2026 refrac program; and our Pembina Duvernay development plans. 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 (including as a result of tariffs); risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; 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.*

Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) or acquire Common Shares pursuant to a share buyback (including through the current Normal Course Issuer Bid) 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. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2024 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 2025 guidance for development expenditures; our expected 2025 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.

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 total sales, net of blending and other expense, operating netback, free cash flow, and working capital deficiency) 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			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Petroleum and natural gas sales	**$ 886,579**	$ 999,130	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Blending and other expense	**(62,381)**	(72,820)	(67,685)	**(135,201)**	(131,893)
Total sales, net of blending and other expense	**$ 824,198**	$ 926,310	$ 1,065,438	**$ 1,750,508**	$ $ 1,985,422
Royalties	**(177,390)**	(207,937)	(240,440)	**(385,327)**	(449,611)
Operating expense	**(161,020)**	(147,703)	(167,705)	**(308,723)**	(341,140)
Transportation expense	**(32,907)**	(30,512)	(33,314)	**(63,419)**	(63,149)
Operating netback	**$ 452,881**	$ 540,158	$ 623,979	**$ 993,039**	$ 1,131,522
Realized financial derivatives (loss) gain (1)	**(11,874)**	(194)	(2,257)	**(12,068)**	3,231
Operating netback after realized financial derivatives	**$ 441,007**	$ 539,964	$ 621,722	**$ 980,971**	$ 1,134,753

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See the Financial Instruments and Risk Management note within the consolidated financial statements for the respective period end for further information.

Free cash flow

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

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

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Cash flows from operating activities	**$ 354,312**	$ 431,317	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	29,034	20,140	**38,076**	52,163
Additions to exploration and evaluation assets	**(930)**	-	-	**(930)**	-
Additions to oil and gas properties	**(355,602)**	(405,097)	(339,573)	**(760,699)**	(752,124)
Payments on lease obligations	**(3,634)**	(2,725)	(5,478)	**(6,359)**	(10,350)
Transaction costs	**-**	-	-	**-**	1,539
Free cash flow	**$ 3,188**	$ 52,529	$ 180,673	**$ 55,717**	$ 180,585

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, share-based compensation liability, dividends payable, and other long-term liabilities. Working capital deficiency is used by management to measure the Company's liquidity. At June 30, 2025, the Company had $1.2 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)	**June 30, 2025**	March 31, 2025	June 30, 2024
Cash$	**$ (7,156)**	$ (5,966)	$ (35,887)
Trade receivables	**(363,507)**	(391,905)	(429,098)
Prepaids and other assets	**(75,856)**	(72,045)	(81,805)
Trade payables	**538,330**	582,053	617,222
Share-based compensation liability	**13,851**	12,602	22,706
Dividends payable	**17,304**	17,334	19,845
Other long-term liabilities	**19,751**	20,849	18,161
Working capital deficiency	**$ 142,717**	$ 162,922	$ 131,144

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.

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)	**June 30, 2025**	March 31, 2025	June 30, 2024
Credit facilities	**$ 317,310**	$ 234,683	$ 607,589
Unamortized debt issuance costs - Credit facilities [1]	**16,206**	15,601	18,387
Long-term notes	**1,776,647**	1,930,809	1,833,182
Unamortized debt issuance costs - Long-term notes [1]	**41,060**	46,235	48,712
Trade payables	**538,330**	582,053	617,222
Share-based compensation liability	**13,851**	12,602	22,706
Dividends payable	**17,304**	17,334	19,845
Other long-term liabilities	**19,751**	20,849	18,161
Cash	**(7,156)**	(5,966)	(35,887)
Trade receivables	**(363,507)**	(391,905)	(429,098)
Prepaids and other assets	**(75,856)**	(72,045)	(81,805)
Net debt	**$ 2,293,940**	$ 2,390,250	$ 2,639,014

(1) Unamortized debt issuance costs were obtained from the Long-term Notes and Credit Facilities notes within the consolidated financial statements for the respective period end.

Adjusted funds flow

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

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

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Cash flow from operating activities	**$ 354,312**	$ 431,317	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	29,034	20,140	**38,076**	52,163
Asset retirement obligations settled	**3,565**	3,519	7,115	**7,084**	13,626
Transaction costs	**-**	-	-	**-**	1,539
Adjusted funds flow	**$ 366,919**	$ 463,870	$ 532,839	**$ 830,789**	$ 956,685

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 six months ended June 30, 2025 and 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 June 30, 2025	**Three Months Ended June 30, 2024**
	Light and	**Light and**

	Heavy Crude Oil (bbl/d)	Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Crude Oil (bbl/d)	Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy										
Peace River	9,308	14	34	9,845	10,997	9,116	7	41	10,733	10,953
Lloydminster	12,456	20	-	1,148	12,667	13,688	16	-	1,607	13,972
Peavine	19,662	-	-	-	19,662	19,938	-	-	-	19,938
Remaining Properties	1,439	2	-	770	1,569	957	1	-	535	1,047
Canada - Light										
Viking	89	7,603	198	10,761	9,684	-	8,130	181	10,586	10,075
Duvernay	-	3,180	2,166	7,915	6,665	-	2,509	1,640	5,875	5,128
Remaining Properties	5	348	588	11,892	2,923	4	413	447	10,263	2,575
United States										
Eagle Ford	-	50,941	16,962	96,151	83,928	-	55,955	17,858	100,165	90,506
Total	42,959	62,108	19,948	138,482	148,095	43,703	67,031	20,167	139,764	154,194

	Six Months Ended June 30, 2025					Six Months Ended June 30, 2024				
	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	9,758	12	26	9,734	11,418	9,299	8	44	10,411	11,086
Lloydminster	11,905	17	-	1,169	12,117	13,422	15	-	1,519	13,690
Peavine	18,693	-	-	-	18,693	18,768	-	-	-	18,768
Remaining Properties	1,122	1	-	707	1,241	635	47	-	267	727
Canada - Light										
Viking	100	8,277	176	10,541	10,310	-	8,655	185	10,827	10,645
Duvernay	-	2,794	2,193	7,313	6,206	-	2,156	1,699	5,665	4,799
Remaining Properties	5	368	659	13,569	3,294	7	404	542	13,301	3,169
United States										
Eagle Ford	-	50,752	16,445	94,081	82,877	-	55,249	17,263	102,069	89,523
Total	41,583	62,221	19,499	137,114	146,156	42,131	66,534	19,733	144,059	152,407

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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