Baytex Announces Third Quarter 2023 Results

Calgary, Alberta--(Newsfile Corp. - November 2, 2023) - Baytex Energy Corp. (TSX: BTE) (NYSE: BTE) ("Baytex") reports its operating and financial results for the three and nine months ended September 30, 2023 (all amounts are in Canadian dollars unless otherwise noted).

"Our third quarter results represent the first full quarter of combined operations following the Ranger acquisition and demonstrate the strength of our diversified North American oil-weighted portfolio. The integration has progressed extremely well and we have delivered strong results from Western Canada and the Eagle Ford in Texas. We are building momentum with current production exceeding 155,000 boe/d (84% oil and NGLs). Currently, we expect to generate free cash flow of approximately $400 million in Q4/2023 and $650 million for this year. As a result of this strong free cash flow, we have increased the pace of our share buyback program during the fourth quarter. We are also excited to announce two new land extensions at Peavine and Cold Lake as we continue to leverage our heavy oil expertise and recent exploration successes," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Generated production of 150,600 boe/d (85% oil and NGLs) in Q3/2023.
- Reported cash flows from operating activities of $444 million ($0.52 per basic share) in Q3/2023.
- Delivered adjusted funds flow(1) of $582 million ($0.68 per basic share) in Q3/2023.
- Generated free cash flow(2) of $158 million ($0.19 per basic share) in Q3/2023.
- Exploration and development expenditures totaled $409 million in Q3/2023, consistent with our full-year plan.
- Repurchased 16.8 million common shares in Q3/2023, representing 2.0% of our shares outstanding, at an average price of $5.29 per share.
- Paid a quarterly cash dividend of $0.0225 per share ($0.09 per share annualized) on October 2, 2023.
- Brought 13 operated Eagle Ford wells onstream in Q3/2023, of which seven wells from three pads generated average 30-day initial production rates of approximately 2,000 boe/d (65% oil and NGLs) per well.
- Executed a two-rig drilling program at Peavine and brought 14 Clearwater wells onstream. Production at Peavine averaged 13,821 bbl/d in Q3/2023, up 69% from Q3/2022. Production during September averaged 16,400 bbl/d.
- Continued commercialization program in our Pembina Duvernay with six-well program delivering strong results.
- Expanded our heavy oil development fairway through two land extensions, including a 10-section agreement with the Peavine Métis settlement adjacent to our existing 80 section land position and a farm-in on 17.75 sections of land prospective for Mannville development near Cold Lake in northeast Alberta.

Quarterly Dividend

The Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 2, 2024 for shareholders of record on December 15, 2023.

(1) Capital management measure. Refer to the Specified Financial Measures 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.

2023 Outlook

We continue to execute our 2023 plan and anticipate full-year 2023 production of 121,500 to 122,000 boe/d (previous guidance range of 120,500 to 122,500 boe/d). Production during the fourth quarter is expected to average 158,000 to 160,000 boe/d, 84% weighted to oil and NGLs (47% light oil, 24% heavy oil and 13% NGLs) and 16% natural gas. We anticipate full-year 2023 exploration and development expenditures of approximately $1,035 million, consistent with our previous guidance range of $1,005 to $1,045 million. Based on the forward strip for the balance of 2023(1), we expect to generate free cash flow(2) of approximately $400 million ($0.48 per basic share) in Q4/2023 and $650 million ($0.92 per basic share) for the full-year 2023.

The following table summarizes our 2023 guidance for production and exploration and development expenditures.

	H1/2023 Actual	Q3/2023 Actual	Q4/2023 Estimate	2023 Guidance
Production (boe/d)	88,269 (3)	150,600 (4)	158,000 - 160,000	121,500 - 122,000
Exploration and development expenditures ($ millions)	$404	$409	~$222	~$1,035

The following table summarizes our 2023 guidance for expenses, leasing expenditures and asset retirement obligations.

Guidance for unit operating expenses moves to the high end of our previous range to reflect incremental base optimization and workover activity in the Eagle Ford. Guidance for interest expense is higher due largely to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

	2023 Guidance(5)	2023 Revised Guidance
Expenses:		
Average royalty rate (2)	21.0 - 22.0%	no change
Operating (6)	$12.25 - $12.75/boe	~ $12.75/boe
Transportation (6)	$2.00 - $2.10/boe	~ $2.10/boe
General and administrative (6)	$80 million ($1.80/boe)	no change

Interest (6)	$150 million ($3.38/boe)	$156 million ($3.50/boe)
Leasing expenditures	$13 million	no change
Asset retirement obligations	$25 million	no change

Our 2024 capital budget is expected to be released in early December following approval by our Board of Directors.

Shareholder Returns

In conjunction with closing the Ranger Oil Corporation ("Ranger") transaction, we increased direct shareholder returns to 50% of free cash flow(2) which has allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow continues to be allocated to the balance sheet.

Our normal course issuer bid allows for the purchase of up to 68.4 million common shares during the 12-month period ending June 28, 2024. During the third quarter, we repurchased 16.8 million common shares for $89 million, representing 2.0% of our shares outstanding, at an average price of $5.29 per share. Through October 31, 2023, we repurchased 28.1 million common shares for $155.0 million, representing 3.3% of our shares outstanding, at an average price of $5.51 per share. In addition, we paid an initial quarterly cash dividend of $0.0225 per share ($0.09 per share annualized) on October 2, 2023.

As of September 30, 2023, our total debt(7) was $2.7 billion, representing a total debt to EBITDA(7) ratio (Q3/2023 annualized) of 1.1x. Our total debt at quarter-end increased relative to Q2/2023 due to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt, and working capital adjustments. Based on current commodity prices and forecast free cash flow for the fourth quarter, we expect to exit 2023 with total debt of approximately $2.5 billion.

(1) Q4/2023 commodity prices: WTI - US$84/bbl, WCS differential to WTI - US$21/bbl, NYMEX Gas - US$3.00/MMbtu; Exchange Rate (CAD/USD) - 1.38.
(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) H1/2023 actual production is comprised of 33,510 bbl/d of light crude oil and medium crude oil (including condensate), 33,502 bbl/d of heavy crude oil, 7,920 bbl/d of natural gas liquids and 80,017 mcf/d of conventional natural gas.
(4) Q3/2023 actual production is comprised of 75,763 bbl/d of light crude oil and medium crude oil (including condensate), 35,204 bbl/d of heavy crude oil, 18,004 bbl/d of natural gas liquids and 129,780 mcf/d of conventional natural gas.
(5) As announced on July 27, 2023. Includes Ranger from the closing date of the transaction (June 20, 2023).
(6) Calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(7) Calculated in accordance with the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,163,010**	$ 598,760	$ 712,065	**$ 2,317,106**	$ 2,240,059
Adjusted funds flow (1)	**581,623**	273,590	284,288	**1,092,202**	909,599
Per share - basic	**0.68**	0.47	0.51	**1.65**	1.62
Per share - diluted	**0.68**	0.47	0.51	**1.64**	1.60
Free cash flow (2)	**158,440**	96,313	111,568	**252,835**	478,202
Per share - basic	**0.19**	0.17	0.20	**0.38**	0.85
Per share - diluted	**0.18**	0.16	0.20	**0.38**	0.84
Cash flows from operating activities	**444,033**	192,308	310,423	**821,279**	869,431
Per share - basic	**0.52**	0.33	0.56	**1.24**	1.55
Per share - diluted	**0.52**	0.33	0.56	**1.23**	1.53
Net income	**127,430**	213,603	264,968	**392,474**	502,798
Per share - basic	**0.15**	0.37	0.48	**0.59**	0.89
Per share - diluted	**0.15**	0.36	0.47	**0.59**	0.89
Dividends declared	**19,138**	-	-	**19,138**	-
Per share	**0.0225**	-	-	**0.0225**	-
Capital Expenditures					
Exploration and development expenditures	**$ 409,191**	$ 170,704	$ 167,453	**$ 813,521**	$ 417,908
Acquisitions and divestitures	**4,051**	(112)	(25,460)	**4,210**	(25,234)
Net oil and natural gas capital expenditures	**$ 413,242**	$ 170,592	$ 141,993	**$ 817,731**	$ 392,674
Net Debt					
Credit facilities	**$ 1,046,756**	$ 986,903	$ 450,051	**$ 1,046,756**	$ 450,051
Long-term notes	**1,637,640**	1,601,468	648,207	**1,637,640**	648,207
Total debt (3)	**2,684,396**	2,588,371	1,098,258	**2,684,396**	1,098,258
Working capital	**139,952**	226,473	15,301	**139,952**	15,301
Net debt (1)	**$ 2,824,348**	$ 2,814,844	$ 1,113,559	**$ 2,824,348**	$ 1,113,559
Shares Outstanding - basic (thousands)					
Weighted average	**855,300**	583,365	553,409	**662,379**	561,931
End of period	**845,360**	862,192	547,615	**845,360**	547,615
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 82.26**	$ 73.78	$ 91.56	**$ 77.39**	$ 98.09
MEH oil (US$/bbl)	**84.10**	75.01	96.15	**78.84**	101.76
MEH oil differential to WTI (US$/bbl)	**1.84**	1.23	4.59	**1.45**	3.67
Edmonton par ($/bbl)	**107.93**	95.13	116.79	**100.70**	123.41
Edmonton par differential to WTI (US$/bbl)	**(1.78)**	(2.95)	(2.13)	**(2.54)**	(1.89)
WCS heavy oil ($/bbl)	**93.02**	78.85	93.62	**80.47**	105.65
WCS differential to WTI (US$/bbl)	**(12.89)**	(15.07)	(19.87)	**(17.57)**	(15.74)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.55**	$ 2.10	$ 8.20	**$ 2.69**	$ 6.77
AECO ($/mcf)	**2.39**	2.35	5.81	**3.03**	5.56
CAD/USD average exchange rate	**1.3410**	1.3431	1.3059	**1.3453**	1.2829

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**75,763**	35,322	33,247	**47,750**	33,437
Heavy oil (bbl/d)	**35,204**	32,821	29,244	**34,076**	27,703
NGL (bbl/d)	**18,004**	8,620	7,536	**11,318**	7,547
Total liquids (bbl/d)	**128,971**	76,763	70,027	**93,144**	68,686
Natural gas (mcf/d)	**129,780**	77,989	79,003	**96,787**	82,232
Oil equivalent (boe/d @ 6:1) (4)	**150,600**	89,761	83,194	**109,275**	82,392
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 1,113,180**	$ 545,765	$ 671,120	**$ 2,154,600**	$ 2,100,779
Royalties	**(240,049)**	(107,920)	(146,994)	**(441,222)**	(441,273)
Operating expense	**(174,119)**	(119,438)	(110,139)	**(405,965)**	(318,331)
Transportation expense	**(27,983)**	(14,574)	(12,771)	**(59,562)**	(33,744)
Operating netback (2)	**$ 671,029**	**$ 303,833**	**$ 401,216**	**$ 1,247,851**	**$ 1,307,431**
General and administrative	**(20,536)**	(15,240)	(12,003)	**(47,510)**	(35,325)
Cash financing and interest	**(56,495)**	(28,255)	(19,774)	**(103,125)**	(60,675)
Realized financial derivatives gain (loss)	**2,055**	16,365	(76,408)	**23,835**	(284,816)
Other (5)	**(14,430)**	(3,113)	(8,743)	**(28,849)**	(17,016)
Adjusted funds flow (1)	**$ 581,623**	**$ 273,590**	**$ 284,288**	**$ 1,092,202**	**$ 909,599**
Netback (per boe) (6)					
Total sales, net of blending and other expense (2)	**$ 80.34**	$ 66.82	$ 87.68	**$ 72.22**	$ 93.40
Royalties	**(17.33)**	(13.21)	(19.21)	**(14.79)**	(19.62)
Operating expense	**(12.57)**	(14.62)	(14.39)	**(13.61)**	(14.15)
Transportation expense	**(2.02)**	(1.78)	(1.67)	**(2.00)**	(1.50)
Operating netback (2)	**$ 48.42**	**$ 37.21**	**$ 52.41**	**$ 41.82**	**$ 58.13**
General and administrative	**(1.48)**	(1.87)	(1.57)	**(1.59)**	(1.57)
Cash financing and interest	**(4.08)**	(3.46)	(2.58)	**(3.46)**	(2.70)
Realized financial derivatives gain (loss)	**0.15**	2.00	(9.98)	**0.80**	(12.66)
Other (4)	**(1.03)**	(0.39)	(1.14)	**(0.96)**	(0.76)
Adjusted funds flow (1)	**$ 41.98**	**$ 33.49**	**$ 37.14**	**$ 36.61**	**$ 40.44**

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 the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(4) 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.
(5) 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 Q3/2023 MD&A for further information on these amounts.
(6) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest expense or realized financial derivatives loss divided by barrels of oil equivalent production volume for the applicable period.

Q3/2023 Results

Our third quarter results represent the first full quarter of operations following the acquisition of Ranger and demonstrate the strength of our diversified North American oil weighted portfolio. We continue to integrate the Ranger assets and execute our development program with strong results in Western Canada and the Eagle Ford.

Production during the third quarter averaged 150,600 boe/d (85% oil and NGLs). We delivered adjusted funds flow(1) of $582 million ($0.68 per basic share), cash flows from operating activities of $444 million ($0.52 per basic share) and net income of $127 million ($0.15 per basic share) in Q3/2023. Exploration and development expenditures totaled $409 million in Q3/2023 and we brought 105 (87.8 net) wells onstream. During the third quarter, we generated free cash flow(2) of $158 million ($0.19 per basic share).

Operating Results

Light Oil - United States

Our light oil assets in the United States are located in the liquids-rich Eagle Ford formation, in the Texas Gulf Coast Basin. The Ranger acquisition materially increased the scale of our Eagle Ford operations, adding 162,000 operated net acres in the crude oil window on-trend with our non-operated position in the Karnes Trough. The transaction increased our exposure to premium U.S. Gulf Coast pricing and includes substantial infrastructure in place with low operating and transportation costs.

Production in the Eagle Ford averaged 87,311 boe/d (85% oil and NGLs) during Q3/2023. During the third quarter, we brought 36 (21.3 net) wells onstream, including 13 (12.9 net) operated wells. The third quarter program reflects strong results across the black oil and condensate thermal maturity windows of the Lower Eagle Ford. The 13 operated wells generated an average 30-day initial production rate of 1,495 boe/d (78% oil and NGLs) per well (ranging from 769 boe/d to 2,355 boe/d). Seven wells from three pads (Bloodstone, Bubinga and Hickory) generated an average 30-day initial production rate of 2,000 boe/d (65% oil and NGLs) per well.

Given the timing of on-streaming wells, production in the Eagle Ford increased to over 92,000 boe/d in September. In addition to delivering strong results, we remain focused on base optimization and continued strong drilling and completion performance.

Light Oil - Canada

Our light oil production and development in Canada occurs from the Viking formation in west-central Saskatchewan and east-central Alberta, and the Duvernay formation in the Pembina area of central Alberta. The Viking is a shallow and highly repeatable light oil resource play with some of the highest operating netbacks in North America. Our Pembina Duvernay light oil assets are in the demonstration stage of commerciality and offer high operating netbacks, with strong economics and the potential for significant organic growth.

Our light oil production in Canada averaged 21,088 boe/d (87% oil and NGLs) during Q3/2023. In the Viking, we brought 38 (35.5 net) wells onstream in Q3/2023. In the Pembina Duvernay, commercialization continued with our six-well program (two-three well pads) delivering strong results with production increasing to over 7,500 boe/d in September (up from 2,000 boe/d in H1/2023). The six wells generated average production rates of approximately 950 boe/d (89% oil and NGLs) in September (ranging from 790 boe/d to 1,080 boe/d) and continue to track to type curve expectations. The 2023 program has advanced our understanding of the reservoir as we continue to progress this light oil resource play.

Heavy Oil - Canada

Our heavy oil production and development in Canada occurs within the Bluesky and Spirit River (Clearwater) formations in the Peace River area of northwest Alberta and the Mannville group of formations in the greater Lloydminster region of east central Alberta and west central Saskatchewan. Our heavy oil business includes the use of innovative multi-lateral horizontal drilling with strong capital efficiencies. The core of our Clearwater play is located on the Peavine Métis settlement.

Our heavy oil assets produced a combined 37,507 boe/d (94% oil and NGLs) during Q3/2023. Following a relatively quiet second quarter due to spring breakup, our heavy oil development program ramped up during the third quarter with 25 net heavy oil wells onstream, 14 at Peavine, 8 at Lloydminster and 3 at Peace River. At Peavine, the 14 wells generated an average 30-day initial production rate of 725 bbl/d per well (ranging from 330 bbl/d to 1,073 bbl/d). Production at Peavine averaged 13,821 bbl/d in Q3/2023, up 69% from Q3/2022, and 16,400 bbl/d during the month of September.

(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.

We are following up on our recent heavy oil exploration success at Morinville, Alberta and Cold Lake, Alberta. At Morinville, where we have aggregated approximately 30 sections of prospective land, we drilled two Clearwater equivalent test wells during the third quarter with the wells placed on production in Q4/2023. At Cold Lake, where we hold 20 sections of land prospective for the Waseca formation, we expect to drill 3 follow-up wells in Q4/2023, including a Lower Waseca test.

Building on our heavy oil expertise, we have expanded our heavy oil development fairway through two land extensions, including a 10-section agreement with the Peavine Métis settlement adjacent to our existing 80 section land position and a farm-in on 17.75 sections of land prospective for Mannville development near Cold Lake in northeast Alberta.

Financial Liquidity

We are well capitalized and have significant liquidity on our credit facilities. We have a US$1.1 billion revolving credit facility with a maturity date of April 1, 2026. During the third quarter, we repaid our US$150 million term loan.

As at September 30, 2023, our total debt(1), which includes our two series of long-term notes, is $2.7 billion and we maintain strong liquidity with approximately 30% undrawn capacity on our revolving credit facility. Our total debt at quarter-end increased relative to Q2/2023 due to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt, and working capital adjustments.

Risk Management

We employ a disciplined commodity hedging program to help mitigate the volatility in revenue due to changes in commodity prices.

For Q4/2023, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing a combination of two-way collars with a floor price of US$60/bbl and a ceiling price of US$100/bbl and a 5,000 bbl/d purchased put at US$60/bbl.

For the first half of 2024, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing two-way collars with a floor price of US$60/bbl and a ceiling price of US$100/bbl. For the second half of 2024, we have entered into hedges on approximately 25% of our net crude oil exposure utilizing two-way collars with a floor price of US$60/bbl and a ceiling price of US$98/bbl.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q3/2023 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2023 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.com and EDGAR at www.sec.gov/edgar.shtml.

(1) Calculated in accordance with the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com

Conference Call Tomorrow **9:00 a.m. MDT (11:00 a.m. EDT)**
Baytex will host a conference call tomorrow, November 3, 2023, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter https://services.choruscall.ca/links/baytex2023q3.html in your web browser. 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 expect to generate over $400 million of free cash flow in Q4 of 2023, and approximately $650 million of free cash flow for the full-year 2023; our guidance for 2023 exploration and development expenditures, production (including production mix by product type), royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; our expected total debt at year-end 2023; our plans for follow up wells to be drilled at Cold Lake, Alberta and Morinville, Alberta; and our hedging plans.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; that our core assets have more than 10 years development inventory at the current pace of development; 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, including operating and transportation costs; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our hedging program; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; 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: risks relating to any unforeseen liabilities of Baytex; that Baytex fails to meet its guidance; the volatility of oil and natural gas prices and price differentials (including the impacts of COVID-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties, including transportation costs; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; 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 of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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, 2022, 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 newinformation, future events or otherwise, except as may be required by applicable securities law.

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, 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 natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers. In addition, this press release contains the terms "adjusted funds flow" and "net debt" which are considered capital management measures.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense is not a measurement based on GAAP in Canada and represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

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, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Petroleum and natural gas sales	**$ 1,163,010**	$ 598,760	$ 712,065	**$ 2,317,106**	$ 2,240,059
Blending and other expense	**(49,830)**	(52,995)	(40,945)	**(162,506)**	(139,280)
Total sales, net of blending and other expense	**1,113,180**	545,765	671,120	**2,154,600**	2,100,779
Royalties	**(240,049)**	(107,920)	(146,994)	**(441,222)**	(441,273)
Operating expense	**(174,119)**	(119,438)	(110,139)	**(405,965)**	(318,331)
Transportation expense	**(27,983)**	(14,574)	(12,771)	**(59,562)**	(33,744)
Operating netback	**$ 671,029**	$ 303,833	$ 401,216	**$ 1,247,851**	$ 1,307,431

Free cash flow

Free cash flowis not a measurement based on GAAP in Canada. We define free cash flowas 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. Our determination of free cash flowmay not be comparable to other issuers. We use free cash flowto evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

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

	Three Months Ended			Nine Months Ended	
($ thousands)	**September 30, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Cash flows from operating activities	**$ 444,033**	$ 192,308	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	40,795	(30,734)	**205,924**	29,560
Additions to exploration and evaluation assets	**(40)**	(741)	-	**(1,271)**	(5,897)
Additions to oil and gas properties	**(409,151)**	(169,963)	(167,453)	**(812,250)**	(412,011)

Payments on lease obligations	**(4,740)**	(1,181)	(668)	**(7,076)**	(2,881)
Transaction costs	**2,263**	32,832	-	**43,966**	-
Cash premiums on derivatives	**-**	2,263	-	**2,263**	-
Free cash flow	**$ 158,440**	$ 96,313	$ 111,568	**$ 252,835**	$ 478,202

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. 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 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 define net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs adjusted for trade and other payables, cash, and trade receivables and prepaids. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provide a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**September 30, 2023**	June 30, 2023	December 31, 2022
Credit facilities	**$ 1,028,867**	$ 964,332	$ 383,031
Unamortized debt issuance costs - Credit facilities [(1)]	**17,889**	22,571	2,363
Long-term notes	**1,600,397**	1,563,897	547,598
Unamortized debt issuance costs - Long-term notes [(1)]	**37,243**	37,571	6,999
Trade and other payables	**685,392**	616,608	281,404
Dividends payable	**19,138**	-	-
Cash	**(23,899)**	(19,637)	(5,464)
Trade receivables and prepaids	**(540,679)**	(370,498)	(228,485)
Net debt	**$ 2,824,348**	$ 2,814,844	$ 987,446

(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, 2023.

Adjusted funds flow

Adjusted funds flow is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.

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, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Cash flow from operating activities	**$ 444,033**	$ 192,308	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	40,795	(30,734)	**205,924**	29,560
Asset retirement obligations settled	**9,252**	5,392	4,599	**18,770**	10,608
Transaction costs	**2,263**	32,832	-	**43,966**	-
Cash premiums on derivatives	**-**	2,263	-	**2,263**	-

Adjusted funds flow	**$ 581,623**	$ 273,590	$ 284,288	**$ 1,092,202**	$ 909,599

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 initial 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 oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 2023. 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, 2023					Three Months Ended September 30, 2022				
	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	9,766	8	45	12,075	11,831	10,282	13	41	12,026	12,340
Lloydminster	11,617	20	-	1,300	11,854	10,770	4	-	1,575	11,037
Peavine	13,821	-	-	-	13,821	8,191	-	-	-	8,191
Canada - Light										
Viking	-	14,074	253	12,015	16,330	-	13,908	191	11,516	16,019
Duvernay	-	2,962	1,130	3,996	4,758	-	1,894	959	3,305	3,405
Remaining Properties	-	577	674	20,672	4,695	-	690	682	20,638	4,811
United States										
Eagle Ford	-	58,122	15,902	79,722	87,311	-	16,738	5,663	29,943	27,391
Total	35,204	75,763	18,004	129,780	150,600	29,244	33,247	7,536	79,003	83,194

	Nine Months Ended September 30, 2023					Nine Months Ended September 30, 2022				
	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	10,113	9	49	11,488	12,086	10,691	9	33	11,877	12,713
Lloydminster	11,554	18	-	1,249	11,780	10,773	9	-	1,696	11,065
Peavine	12,409	-	-	-	12,409	6,240	-	-	-	6,240
Canada - Light										
Viking	-	13,991	210	11,915	16,186	-	14,562	188	12,203	16,783
Duvernay	-	1,573	881	2,860	2,931	-	1,233	790	2,555	2,449
Remaining Properties	-	631	664	19,565	4,556	-	769	864	22,972	5,461
United States										
Eagle Ford	-	31,528	9,514	49,710	49,327	-	16,855	5,671	30,929	27,681
Total	34,076	47,750	11,318	96,787	109,275	27,703	33,437	7,546	82,232	82,392

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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