BAYTEX ANNOUNCES THIRD QUARTER 2021 FINANCIAL AND OPERATING RESULTS, FREE CASH FLOW OF $101 MILLION AND REPURCHASE OF LONG-TERM NOTES

CALGARY, ALBERTA (November 4, 2021) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and nine months ended September 30, 2021 (all amounts are in Canadian dollars unless otherwise noted).

"During the third quarter, we remain focused on strong capital discipline, generating free cash flow and reducing debt. We have already repurchased and cancelled US$200 million of our 2024 bonds this year and at current commodity prices we now expect to generate record levels of free cash flow in excess of $400 million. Our operating results continue to build momentum as we appraise and develop our Clearwater oil play at Peace River. We have some of the best results in all of the Clearwater, and will now drill four additional wells during the fourth quarter, which will enable us to accelerate our development plans in 2022," commented Ed LaFehr, President and Chief Executive Officer.

Q3 2021 Highlights

- Generated production of 79,872 boe/d (82% oil and NGL) in Q3/2021 and 79,942 boe/d (81% oil and NGL) for the first nine months of 2021.
- Delivered adjusted funds flow of $198 million ($0.35 per basic share) in Q3/2021 and $531 million ($0.94 per basic share) for the first nine months of 2021.
- Generated free cash flow of $101 million ($0.18 per basic share) in Q3/2021 and $284 million ($0.50 per basic share) for the first nine months of 2021.
- Reduced net debt by $65 million during the third quarter and by $283 million through the first nine months of 2021.
- Subsequent to quarter-end, repurchased and cancelled US$85 million principal amount of 5.625% long-term notes, bringing the total repurchased and cancelled to US$200 million (50% of the original principal amount outstanding).

2021 Outlook

As a result of our strong operating performance through the first nine months of 2021, we are tightening our production guidance to 79,500 to 80,000 boe/d, up from 79,000 to 80,000 boe/d, previously.

We are intensely focused on maintaining capital discipline. The Clearwater has emerged as one of the most profitable plays in Canada and our 2021 appraisal program has delivered exceptional results. As a result, we will drill four additional Clearwater wells during the fourth quarter which are expected to be on-stream in late 2021. Accordingly, we are tightening our forecast 2021 exploration and development expenditures range to $300 to $315 million, as compared to $285 to $315 million, previously.

At current commodity prices, we expect to deliver over $400 million ($0.71 per basic share) of free cash flow this year, which has accelerated our debt reduction efforts.

Five-Year Outlook

Our five-year outlook (2021 to 2025) highlights our financial and operational sustainability and meaningful free cash flow generation. Through this plan period, we are committed to a disciplined, returns based capital allocation philosophy. Under constant US$65/bbl and US$75/bbl WTI pricing scenarios, we expect to generate cumulative free cash flow of approximately $2.0 billion and $2.6 billion, respectively.

Based on the strong pricing environment and continued capital discipline, we now anticipate hitting our initial net debt target of $1.2 billion during Q2/2022. Throughout the plan period we will monitor our leverage position and assess market conditions to determine the best methods or combination thereof to enhance shareholder returns. These could include share buy-backs, a dividend and/or reinvestment for organic growth.

Our 2022 capital budget is expected to be released in early December following approval by our Board of Directors. We will also update our five-year plan to include drilling opportunities on our Clearwater lands.

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	**September 30, 2021**	September 30, 2020
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 488,736**	$ 442,354	$ 252,538	**$ 1,315,792**	$ 741,841
Adjusted funds flow [1]	**198,397**	175,883	78,508	**530,862**	229,330
Per share - basic	**0.35**	0.31	0.14	**0.94**	0.41
Per share - diluted	**0.35**	0.31	0.14	**0.93**	0.41
Net income (loss)	**32,713**	1,052,999	(23,444)	**1,050,361**	(2,660,124)
Per share - basic	**0.06**	1.87	(0.04)	**1.86**	(4.75)
Per share - diluted	**0.06**	1.85	(0.04)	**1.84**	(4.75)
Capital Expenditures					
Exploration and development expenditures [1]	**$ 94,235**	$ 61,485	$ 15,902	**$ 239,308**	$ 202,531
Acquisitions, net of divestitures	**(612)**	(18)	(98)	**(833)**	(149)
Total oil and natural gas capital expenditures	**$ 93,623**	$ 61,467	$ 15,804	**$ 238,475**	$ 202,382
Net Debt					
Credit facilities [2]	**$ 546,803**	$ 486,623	$ 624,826	**$ 546,803**	$ 624,826
Long-term notes [2]	**1,000,171**	1,109,211	1,199,160	**1,000,171**	1,199,160
Long-term debt	**1,546,974**	1,595,834	1,823,986	**1,546,974**	1,823,986
Working capital deficiency	**17,684**	33,795	82,093	**17,684**	82,093
Net debt [1]	**$ 1,564,658**	$ 1,629,629	$ 1,906,079	**$ 1,564,658**	$ 1,906,079
Shares Outstanding - basic (thousands)					
Weighted average	**564,211**	564,156	561,128	**563,492**	560,484
End of period	**564,213**	564,182	561,163	**564,213**	561,163
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 70.56**	$ 66.07	$ 40.93	**$ 64.82**	$ 38.32
MEH oil (US$/bbl)	**71.64**	67.15	41.63	**66.05**	39.19
MEH oil differential to WTI (US$/bbl)	**1.08**	1.08	0.70	**1.23**	0.87
Edmonton par ($/bbl)	**83.78**	77.28	49.83	**75.88**	43.70
Edmonton par differential to WTI (US$/bbl)	**(4.07)**	(3.13)	(3.51)	**(4.19)**	(6.04)
WCS heavy oil ($/bbl)	**71.81**	67.03	42.40	**65.47**	33.34
WCS differential to WTI (US$/bbl)	**(13.57)**	(11.48)	(9.09)	**(12.51)**	(13.70)
Natural gas					
NYMEX (US$/mmbtu)	**$ 4.01**	$ 2.83	$ 1.98	**$ 3.18**	$ 1.88
AECO ($/mcf)	**3.54**	2.85	2.18	**3.11**	2.08
CAD/USD average exchange rate	**1.2601**	1.2279	1.3316	**1.2515**	1.3541

	Three Months Ended			Nine Months Ended	
	September 30, 2021	June 30, 2021	September 30, 2020	**September 30, 2021**	September 30, 2020
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**35,614**	37,134	34,101	**36,060**	39,570
Heavy oil (bbl/d)	**21,996**	21,269	22,138	**21,752**	20,946
NGL (bbl/d)	**7,174**	7,563	7,417	**6,995**	7,624
Total liquids (bbl/d)	**64,784**	65,966	63,656	**64,807**	68,140
Natural gas (mcf/d)	**90,528**	91,172	84,945	**90,812**	88,602
Oil equivalent (boe/d @ 6:1) [(3)]	**79,872**	81,162	77,814	**79,942**	82,907
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense [(4)]	**$ 469,155**	$ 422,387	$ 241,865	**$ 1,259,124**	$ 704,351
Royalties	**(90,523)**	(81,531)	(40,052)	**(239,004)**	(125,928)
Operating expense	**(84,196)**	(82,901)	(73,447)	**(247,645)**	(251,597)
Transportation expense	**(7,818)**	(7,486)	(6,372)	**(24,092)**	(21,745)
Operating netback [(1)]	**$ 286,618**	**$ 250,469**	**$ 121,994**	**$ 748,383**	**$ 305,081**
General and administrative	**(9,980)**	(10,610)	(7,741)	**(29,323)**	(24,954)
Cash financing and interest	**(22,793)**	(23,554)	(25,418)	**(70,750)**	(81,340)
Realized financial derivatives (loss) gain	**(53,905)**	(39,024)	(9,743)	**(113,697)**	30,731
Other [(5)]	**(1,543)**	(1,398)	(584)	**(3,751)**	(188)
Adjusted funds flow [(1)]	**$ 198,397**	**$ 175,883**	**$ 78,508**	**$ 530,862**	**$ 229,330**
Netback (per boe)					
Total sales, net of blending and other expense [(4)]	**$ 63.85**	$ 57.19	$ 33.79	**$ 57.69**	$ 31.01
Royalties	**(12.32)**	(11.04)	(5.59)	**(10.95)**	(5.54)
Operating expense	**(11.46)**	(11.22)	(10.26)	**(11.35)**	(11.08)
Transportation expense	**(1.06)**	(1.01)	(0.89)	**(1.10)**	(0.96)
Operating netback [(1)]	**$ 39.01**	**$ 33.92**	**$ 17.05**	**$ 34.29**	**$ 13.43**
General and administrative	**(1.36)**	(1.44)	(1.08)	**(1.34)**	(1.10)
Cash financing and interest	**(3.10)**	(3.19)	(3.55)	**(3.24)**	(3.58)
Realized financial derivatives (loss) gain	**(7.34)**	(5.28)	(1.36)	**(5.21)**	1.35
Other [(5)]	**(0.21)**	(0.20)	(0.09)	**(0.18)**	—
Adjusted funds flow [(1)]	**$ 27.00**	**$ 23.81**	**$ 10.97**	**$ 24.32**	**$ 10.10**

Notes:

(1) The terms “adjusted funds flow”, “exploration and development expenditures”, “net debt” and “operating netback” do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles (“GAAP”) and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of capital or repayment obligations.

(3) 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.

(4) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(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 Q3/2021 MD&A for further information on these amounts.

Q3/2021 Results

During Q3/2021, we delivered strong operating and financial results and continued to advance our exciting new Clearwater play in northwest Alberta with the two strongest initial rate wells drilled to date in the play.

During the quarter, we delivered adjusted funds flow of $198 million ($0.35 per basic share) and net income of $33 million ($0.06 per basic share). We generated free cash flow of $101 million ($0.18 per basic share), which brings our year-to-date free cash flow to $284 million ($0.50 per basic share). We have directed 100% of our free cash flow this year to reduce our net debt, which now sits at $1.56 billion, down from $1.85 billion at the beginning of the year.

Production during the third quarter averaged 79,872 boe/d (82% oil and NGL), as compared to 81,162 boe/d (81% oil and NGL) in Q2/2021. Our operating results reflect strong performance across our light and heavy oil assets in Canada with volumes up 2% over the second quarter, while Eagle Ford volumes were lower due to the number of wells brought on-stream. Exploration and development expenditures totaled $94 million in Q3/2021 that included the drilling of 57 (46.7 net) wells with a 100% success rate.

2021 Guidance

In 2021, we are benefiting from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Based on the forward strip(1), we expect to generate over $400 million of free cash flow in 2021.

We are intensely focused on maintaining capital discipline. The Clearwater has emerged as one of the most profitable plays in Canada and our 2021 appraisal program has delivered production results beyond our initial expectations. As a result, we have committed to drill four additional Clearwater wells during the fourth quarter with the wells expected to be on-stream in late 2021. Accordingly, we are tightening our forecast 2021 exploration and development expenditures range to $300 to $315 million, as compared to $285 to $315 million, previously.

As a result of our continued strong operating performance through the first nine months of 2021, we are also tightening our production guidance range to 79,500 to 80,000 boe/d, up from 79,000 to 80,000 boe/d, previously.

We have also fine-tuned several of our cost assumptions. Our interest expense guidance is 3% lower due to reduced net debt and the repurchase and cancellation of a portion of the 5.625% long-term notes due 2024.

The following table highlights our updated 2021 annual guidance.

	2021 Guidance (2)	**2021 Revised Guidance**
Exploration and development expenditures	$285 - $315 million	$300 - $315 million
Production (boe/d)	79,000 - 80,000	79,500 - 80,000
Expenses:		
Royalty rate	18.0% - 18.5%	18.5% - 19.0%
Operating	$11.25 - $12.00/boe	$11.25 - $11.75/boe
Transportation	$1.15 - $1.25/boe	$1.10 - $1.15/boe
General and administrative	$42 million ($1.45/boe)	$42 million ($1.44/boe)
Interest	$95 million ($3.27/boe)	$92 million ($3.16/boe)
Leasing expenditures	$4 million	no change
Asset retirement obligations	$6 million	no change

Notes:

(1) 2021 full-year pricing assumptions: WTI - US$68/bbl; WCS differential - US$12/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$3.85/mcf; AECO Gas - $3.50/mcf and Exchange Rate (CAD/USD) - 1.25.
(2) As announced on July 28, 2021.

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 31,748 boe/d (79% oil and NGL) during Q3/2021, as compared to 33,957 boe/d in Q2/2021. The lower volumes reflect level of completion activity during the quarter. We commenced production from 17 (3.4 net) wells during the third quarter, as compared to 62 (17.2 net) wells in the first half of 2021. In Q3/2021, we invested $19 million on exploration and development in the Eagle Ford and generated an operating netback of $117 million. We expect to bring approximately 23 net wells on production in the Eagle Ford in 2021.

Production in the Viking averaged 17,132 boe/d (90% oil and NGL) during Q3/2021, as compared to 16,301 boe/d in Q2/2021. We maintained an active pace of development during the third quarter with 23.0 net wells drilled and 37.0 net wells brought on production. In Q3/2021, we invested $29 million on exploration and development and generated an operating netback of $88 million. We expect to bring approximately 115 net wells on production in the Viking during 2021.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development) produced a combined 22,577 boe/d (91% oil and NGL) during the Q3/2021, as compared to 23,304 boe/d in Q2/2021. After a quiet first half of the year, our heavy oil program kicked off during the third quarter and included drilling 2 net Bluesky wells at Peace River and 14 net wells at Lloydminster. In Q3/2021, we invested $18 million on exploration and development in Peace River and Lloydminster and generated an operating netback of $60 million.

Peace River Clearwater

We are committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. In early 2020, we executed a strategic agreement with the Peavine Métis Settlement in the Peace River area that covered 60 sections of land directly to the south of our existing Seal operations. At the time, we identified significant potential for an early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent. In August 2021, we executed a second strategic agreement with the Peavine Métis Settlement that covers an additional 20 sections, bringing our total Peavine acreage to 80 contiguous sections. When combined with our legacy acreage position in northwest Alberta, we estimate that over 120 sections are prospective for Clearwater development.

Production in the Clearwater averaged 1,540 bbl/d during Q3/2021. We currently have five producing wells on our Peavine acreage and production has increased from zero at the beginning of this year to approximately 1,900 bbl/d, currently. Our three eight-lateral wells continue to outperform type curve assumptions and two of our wells rank as the top initial rate wells drilled to-date across the play.

The following table summarizes the results of our 2021 appraisal program.

Area	Well	Spud	Rig Release	# of Laterals	30-Day Initial Production Rate (bbl/d) (1)	Current Production Rate (bbl/d)
Peavine	100/04-34-078-16W5	January 7	January 15	2	175	100
Peavine	102/04-34-078-16W5	June 15	June 21	2	175	170
Peavine	100/13-27-078-16W5	June 22	July 6	8	695	700
Peavine	100/05-34-078-16W5	July 8	July 18	8	412	300
Peavine	102/11-31-078-15W5	July 20	August 4	8	930	645

(1) 30-Day Initial Production Rate (bbl/d) is defined as the average oil rate over the first 720 hours of production following drilling fluid recovery.

As we continue to progress our development plan, we have committed to drill four additional Clearwater wells during the fourth quarter. In addition, as part of our 2022 plan, which is to be confirmed and released in early December 2021, we are working with the Peavine Métis Settlement and are preparing to execute an expanded program of up to 18 wells. To-date, we have de-risked 20 sections of land and pending further success, the play holds the potential for greater than 200 locations. At current commodity prices, the Clearwater generates among the strongest economics within our portfolio with payouts of less than six months and has the ability to grow organically while enhancing our free cash flow profile.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 1,528 boe/d (79% oil and NGL) during Q3/2021, as compared to 1,698 boe/d in Q2/2021. During the third quarter, we drilled two 100% working interest wells and initial flow back rates are very encouraging. The first well (7-8) was brought on-stream October 18 and is currently producing 1,010 boe/d (756 bbl/d oil, 162 bbl/d NGLs and 0.6 mmcf/d of natural gas). The second well (6-8) was brought on-stream October 30 and is currently producing 1,500 boe/d (1,270 bbl/d oil, 147 bbl/d NGLs and 0.5 mmcf/d of natural gas). We now have eleven producing wells in the Pembina area and have significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold approximately 200 sections (100% working interest) of Duvernay land.

Financial Liquidity

Our credit facilities total approximately $1.0 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of September 30, 2021, we had $471 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $454 million.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.56 billion at September 30, 2021, down from $1.63 billion at June 30, 2021.

During 2021, we have repurchased and cancelled US$200 million of the 5.625% long term notes due June 2024. This represents 50% of the original US$400 million outstanding and includes US$84.5 million repurchased and cancelled subsequent to quarter end.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow.

For Q4/2021, we have entered into hedges on approximately 45% of our net crude oil exposure utilizing a combination of fixed price swaps at US$45/bbl and a 3-way option structure that provides price protection at US$44.71/bbl with upside participation to US$52.42/bbl. We also have WTI-MSW differential hedges on approximately 50% of our expected net Canadian light oil exposure at US$5.03/bbl and WCS differential hedges on approximately 45% of our net expected heavy oil exposure at a WTI-WCS differential of approximately US$13.23/bbl.

For 2022, we have entered into hedges on approximately 42% of our net crude oil exposure utilizing a combination of a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl and swaptions at US$53.50/bbl. We also have WTI-MSW differential hedges on approximately 25% of our expected net Canadian light oil exposure at US$4.43/bbl and WCS differential hedges on approximately 70% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.28/bbl.

A complete listing of our financial derivative contracts can be found in Note 16 to our Q3/2021 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2021 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.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, November 5, 2021, 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 http://services.choruscall.ca/links/baytex20211105.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: our business strategies, plans and objectives; that we expect to generate in excess of $400 million of free cash flow in 2021; our plan to drill and bring on-stream four additional wells in the Clearwater in Q4/2021; that our debt reduction will accelerate; our five-year outlook: including that it demonstrates financial and operational sustainability, meaningful free cash flow generation and that we are committed to disciplined and returns based philosophy , the cumulative free cash flow it will generate at certain WTI oil prices and that we anticipate hitting our debt target of $1.2 billion by mid-2022; that we will monitor our leverage position and market conditions to enhance shareholder returns which could be share buy-backs, a dividend or reinvestment for organic growth; that we expect to release our 2022 budget in early December 2021 with an updated five-year plan; we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively; our updated guidance for 2021 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; in 2021 that we expect to: bring on production 23 net wells in the Eagle Ford and 115 in the Viking; that we are committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion; that we have 120 sections of prospective Clearwater lands; that we are preparing to drill up to 18 Clearwater wells in 2022 and believe the play holds the potential for greater than 200 locations; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than six months and has the ability to grow organically while enhancing our free cash flow profile; that we have de-risked our approximately 38-kilometer acreage fairway in the Duvernay; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the MTI-MSW differential and WCS differential that we have hedged for Q4/2021 and 2022.

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; 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; 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 volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); the availability and cost of capital or borrowing; risks associated with our ability to exploit our properties and add reserves; availability and cost of gathering, processing and pipeline systems; 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 a third-party operating our Eagle Ford properties; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; costs to develop and operate our properties; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; results of litigation; risks associated with large projects; 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, 2020, 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.

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

Non-GAAP Financial and Capital Management Measures

In this news release, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP ("non-GAAP measures") and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but 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.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and nine months ended September 30, 2021.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides 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.

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 divided by barrels of oil equivalent sales volume for the applicable period. 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.

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 news 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, 2021. The NI 51-101 product types are included as follows: “Heavy Oil” - heavy oil and bitumen, “Light and Medium Oil” - light and medium oil, tight oil and condensate, “NGL” - natural gas liquids and “Natural Gas” - shale gas and conventional natural gas.

	Three Months Ended September 30, 2021					Nine Months Ended September 30, 2021				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	10,020	7	21	11,220	11,918	11,099	8	22	11,536	13,052
Lloydminster	10,436	3	—	1,319	10,659	10,079	4	—	1,371	10,312
Peavine	1,540	—	—	—	1,540	574	—	—	—	574
Canada - Light										
Viking	—	15,193	145	10,762	17,132	—	15,639	140	10,949	17,603
Duvernay	—	774	436	1,908	1,528	—	903	553	1,979	1,786
Remaining Properties	—	555	628	24,988	5,347	—	576	942	25,581	5,781
United States										
Eagle Ford	—	19,082	5,944	40,331	31,748	—	18,930	5,338	39,396	30,834
Total	21,996	35,614	7,174	90,528	79,872	21,752	36,060	6,995	90,812	79,942

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. 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. Approximately 81% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto 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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