BAYTEX ANNOUNCES THIRD QUARTER 2020 FINANCIAL AND OPERATING RESULTS AND BOARD APPOINTMENT

CALGARY, ALBERTA (November 2, 2020) - Baytex Energy Corp. ("Baytex")(TSX: BTE, NYSE: BTE.BC) reports its operating and financial results for the three and nine months ended September 30, 2020 (all amounts are in Canadian dollars unless otherwise noted).

“We have made tremendous progress to re-set our business in the face of extremely volatile crude oil markets. Our third quarter results demonstrate the success of our actions as we generated free cash flow of $60 million and increased financial liquidity to $344 million. I am also especially pleased with our response to the Covid pandemic with intensified efforts to improve all aspects of our cost structure and capital efficiencies, while protecting the health and safety of our personnel,” commented Ed LaFehr, President and Chief Executive Officer.

Q3 2020 Highlights

- Generated production of 77,814 boe/d (82% oil and NGL) in Q3/2020 and 82,907 boe/d (82% oil and NGL) for the first nine months of 2020.
- Delivered adjusted funds flow of $79 million ($0.14 per basic share) in Q3/2020 and $229 million ($0.41 per basic share) for the first nine months of 2020.
- Generated free cash flow of $60 million ($0.11 per basic share) in Q3/2020 and $16 million ($0.03 per basic share) for the first nine months of 2020.
- Realized an operating netback of $17.05/boe in Q3/2020, up from $5.96/boe in Q2/2020.
- Reduced net debt by $89 million during the third quarter through a combination of free cash flow and the Canadian dollar strengthening relative to the U.S. dollar.
- Maintained undrawn credit capacity of $426 million and liquidity, net of working capital, of $344 million.

2020 Outlook and Revised Guidance

We have responded aggressively to the downturn brought on by Covid-19 as we minimize capital spending, identify cost savings and maintain our liquidity.

We expect production to average approximately 80,000 boe/d, which represents the mid-point of our guidance range of 78,000 to 82,000 boe/d. Annual capital spending is forecast to be $260 to $290 million, an approximate 50% reduction from our original plan of $500 to $575 million.

We are also reducing our full-year 2020 operating expense guidance by 7% (at the mid-point) to $11.20 to $11.40/boe. We remain intensely focused on driving further efficiencies to capture and sustain cost reductions identified during this downturn, while protecting the health and safety of our personnel.

After two quarters of little to no capital spending in Canada, we have resumed drilling activity during the fourth quarter. We have mobilized two drilling rigs to execute a 30-well drilling program in the Viking and completed two Duvernay wells drilled earlier this year. In addition, with the increase in natural gas prices, we have identified opportunities in west-central Alberta at Pembina O’Chiese to drill natural gas wells with strong economics and capital efficiencies and have two wells planned for this winter.

The following table summarizes our updated 2020 guidance. We are in the process of setting our 2021 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

	2020 Guidance (1)	2020 Revised Guidance
Exploration and development expenditures	$260 - $290 million	no change
Production (boe/d)	78,000 - 82,000	~ 80,000
Expenses:		
Royalty rate	~ 18.5%	~ 18%
Operating	$11.75 - $12.50/boe	$11.20 - $11.40/boe
Transportation	$0.95 - $1.05/boe	no change
General and administrative	$38 million ($1.30/boe)	no change
Interest	$112 million ($3.84/boe)	$108 million ($3.70/boe)
Leasing expenditures	$7 million	$6 million
Asset retirement obligations	$10 million	$8 million

Note:
(1) As announced on June 25, 2020

During the third quarter we began to benefit from our actions to reduce capital, capture cost savings and maintain liquidity. We generated free cash flow of $60 million during the quarter and $16 million through the first nine months of this year and also increased our financial liquidity to $344 million.

The following table summarizes the important measures we have undertaken to position us for success as markets recover.

Action	2020 Highlights
Negotiated bank credit facility extension and refinanced long-term notes	• Extended maturity of bank credit facilities to April 2024 • Issued US$500 million principal amount of long-term notes due April 2027 • Redeemed two series of senior unsecured notes – US$400 million due 2021 and $300 million due 2022
Dynamic response to oil price collapse	• Identified cost savings of ~ $100 million, capital budget reduced by ~ 50% • Maintained liquidity of > $300 million • Maintained strong operating efficiency • Active hedge strategy implemented to preserve financial liquidity • Accessed available government assistance
High graded portfolio and economic inventory	• Capital reduction has re-set production base to ~ 75,000 boe/d • Fully funded sustaining capital program at US$40 to US$45/bbl WTI • Improved capital efficiencies and moderated production decline rate
Established Covid-19 task force and flexible working team	• Effective response to Covid-19 with on-going training, communication and work strategies

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	**September 30, 2020**	September 30, 2019
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 252,538**	$ 152,689	$ 424,600	**$ 741,841**	$ 1,360,024
Adjusted funds flow [1]	**78,508**	17,887	213,379	**229,330**	670,279
Per share – basic	**0.14**	0.03	0.38	**0.41**	1.20
Per share – diluted	**0.14**	0.03	0.38	**0.41**	1.20
Net income (loss)	**(23,444)**	(138,463)	15,151	**(2,660,124)**	105,313
Per share – basic	**(0.04)**	(0.25)	0.03	**(4.75)**	0.19
Per share – diluted	**(0.04)**	(0.25)	0.03	**(4.75)**	0.19
Capital Expenditures					
Exploration and development expenditures [1]	**$ 15,902**	$ 9,852	$ 139,085	**$ 202,531**	$ 399,174
Acquisitions, net of divestitures	**(98)**	(11)	(30)	**(149)**	1,617
Total oil and natural gas capital expenditures	**$ 15,804**	$ 9,841	$ 139,055	**$ 202,382**	$ 400,791
Net Debt					
Credit facilities [2]	**$ 624,826**	$ 704,135	$ 570,792	**$ 624,826**	$ 570,792
Long-term notes [2]	**1,199,160**	1,225,395	1,359,480	**1,199,160**	1,359,480
Long-term debt	**1,823,986**	1,929,530	1,930,272	**1,823,986**	1,930,272
Working capital deficiency	**82,093**	65,423	41,067	**82,093**	41,067
Net debt [1]	**$ 1,906,079**	$ 1,994,953	$ 1,971,339	**$ 1,906,079**	$ 1,971,339
Shares Outstanding - basic (thousands)					
Weighted average	**561,128**	560,512	557,888	**560,484**	556,651
End of period	**561,163**	560,545	557,972	**561,163**	557,972
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 40.93**	$ 27.85	$ 56.45	**$ 38.32**	$ 57.06
MEH oil (US$/bbl)	**41.63**	26.40	61.07	**39.19**	62.63
MEH oil differential to WTI (US$/bbl)	**0.70**	(1.45)	4.62	**0.87**	5.57
Edmonton par ($/bbl)	**49.83**	29.85	68.41	**43.70**	69.59
Edmonton par differential to WTI (US$/bbl)	**(3.51)**	(6.31)	(4.66)	**(6.04)**	(4.70)
WCS heavy oil ($/bbl)	**42.40**	22.70	58.39	**33.34**	60.24
WCS differential to WTI (US$/bbl)	**(9.09)**	(11.47)	(12.24)	**(13.70)**	(11.74)
Natural gas					
NYMEX (US$/mmbtu)	**$ 1.98**	$ 1.72	$ 2.23	**$ 1.88**	$ 2.67
AECO ($/mcf)	**2.18**	1.91	1.04	**2.08**	1.39
CAD/USD average exchange rate	**1.3316**	1.3860	1.3207	**1.3541**	1.3292

	Three Months Ended			Nine Months Ended	
	September 30, 2020	June 30, 2020	September 30, 2019	**September 30, 2020**	September 30, 2019
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**34,101**	38,951	42,829	**39,570**	43,479
Heavy oil (bbl/d)	**22,138**	11,832	25,712	**20,946**	26,637
NGL (bbl/d)	**7,417**	7,634	9,543	**7,624**	10,745
Total liquids (bbl/d)	**63,656**	58,417	78,084	**68,140**	80,861
Natural gas (mcf/d)	**84,945**	84,546	101,054	**88,602**	103,587
Oil equivalent (boe/d @ 6:1) (3)	**77,814**	72,508	94,927	**82,907**	98,125
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 241,865**	$ 147,229	$ 411,650	**$ 704,351**	$ 1,309,396
Royalties	**(40,052)**	(29,156)	(75,017)	**(125,928)**	(242,959)
Operating expense	**(73,447)**	(73,680)	(97,377)	**(251,597)**	(298,143)
Transportation expense	**(6,372)**	(5,031)	(9,903)	**(21,745)**	(35,102)
Operating netback (1)	**$ 121,994**	$ 39,362	$ 229,353	**$ 305,081**	$ 733,192
General and administrative	**(7,741)**	(7,438)	(9,934)	**(24,954)**	(35,576)
Cash financing and interest	**(25,418)**	(27,387)	(26,752)	**(81,340)**	(83,028)
Realized financial derivatives gain (loss)	**(9,743)**	13,624	20,857	**30,731**	52,664
Other (5)	**(584)**	(274)	(145)	**(188)**	3,027
Adjusted funds flow (1)	**$ 78,508**	$ 17,887	$ 213,379	**$ 229,330**	$ 670,279
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 33.79**	$ 22.31	$ 47.14	**$ 31.01**	$ 48.88
Royalties	**(5.59)**	(4.42)	(8.59)	**(5.54)**	(9.07)
Operating expense	**(10.26)**	(11.17)	(11.15)	**(11.08)**	(11.13)
Transportation expense	**(0.89)**	(0.76)	(1.13)	**(0.96)**	(1.31)
Operating netback (1)	**$ 17.05**	$ 5.96	$ 26.27	**$ 13.43**	$ 27.37
General and administrative	**(1.08)**	(1.13)	(1.14)	**(1.10)**	(1.33)
Cash financing and interest	**(3.55)**	(4.15)	(3.06)	**(3.58)**	(3.10)
Realized financial derivatives gain (loss)	**(1.36)**	2.06	2.39	**1.35**	1.97
Other (5)	**(0.09)**	(0.03)	(0.03)	**---**	0.11
Adjusted funds flow (1)	**$ 10.97**	$ 2.71	$ 24.43	**$ 10.10**	$ 25.02

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 share-based compensation. Refer to the Q3/2020 MD&A for further information on these amounts.

Q3/2020 Results

Production during the third quarter averaged 77,814 boe/d (82% oil and NGL), as compared to 72,508 boe/d (81% oil and NGL) in Q2/2020. The higher production reflects the re-start of previously shut-in volumes in Canada, partially offset by lower activity in the Viking and Eagle Ford. Our third quarter production was reduced by approximately 5,000 boe/d due to voluntary shut-ins. Exploration and development spending totaled a modest $16 million during the third quarter.

We delivered adjusted funds flow of $79 million ($0.14 per basic share) in Q3/2020 and generated an operating netback of $17.05/boe ($15.69/boe inclusive of realized financial derivatives loss). The Eagle Ford generated an operating netback of $18.99/boe and our Canadian operations generated an operating netback of $15.90/boe.

We continue to emphasize cost reductions across all facets of our organization. Through the first nine months of 2020 our team has driven operating costs down to $11.08/boe, despite lower production volumes. This compares favorably to our guidance range of $11.75 to $12.50/boe. As a result, we are reducing our full-year 2020 operating expense guidance by 7% (at the mid-point) to $11.20 to $11.40/boe.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 28,650 boe/d (77% oil and NGL) during Q3/2020, as compared to 34,817 boe/d in Q2/2020. The lower volumes reflect reduced completion activity as we adjusted our development plan in response to volatile commodity prices. We commenced production from six (0.8 net) wells during the third quarter, as compared to 47 (10.7 net) in the first half of 2020. Activity in the Eagle Ford has recently resumed and we have 0.75 net drilling rigs and 0.5 net frac crews running on our lands. We expect to bring approximately 16 net wells on production in the Eagle Ford in 2020.

Production in the Viking averaged 18,774 boe/d (91% oil and NGL) during Q3/2020, as compared to 19,717 boe/d in Q2/2020. We had previously suspended all drilling in the Viking, and as such, there was limited activity during the third quarter. In the first nine months of 2020, we invested $77 million on exploration and development in the Viking and commenced production from 83 (78.5 net) wells. After two quarters of minimal capital spend, we have resumed drilling activity in the Viking with two drillings rigs mobilized to execute a 30-well drilling program during the fourth quarter.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 24,791 boe/d (89% oil and NGL) during the third quarter, as compared to 13,082 boe/d in Q2/2020. The increased production reflects the re-start of previously shut-in production as operating netbacks improved. The quarterly impact of voluntary shut-ins for heavy oil was approximately 5,000 boe/d, down from 17,000 boe/d in Q2/2020. We currently have approximately 2,000 boe/d of heavy oil production shut-in. We had previously suspended all heavy oil drilling, and as such, there was limited activity during the third quarter. In the first nine month of 2020, we invested $41 million on exploration and development and drilled 33 (33.0 net) wells.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 1,474 boe/d (79% oil and NGL) during Q3/2020, as compared to 717 boe/d in Q2/2020. The increased production during the third quarter reflects the re-start of previously shut-in production as operating netbacks improved.

In Q1/2020, we drilled two wells in the core of our Pembina acreage, bringing total wells drilled to nine in this area. These two wells were fracture stimulated in October using a “plug and perf” system with fracture diversion technology. The wells are scheduled to be placed on production in November. The two wells confirm visibility to a $7.0 million well cost in a full development scenario. The success of our drilling program in the Pembina area has significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold 232 sections (100% working interest) of Duvernay land.

Financial Liquidity

Our credit facilities total approximately $1.07 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, 2020, we had $426 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $344 million. In addition, our first long-term note maturity of US$400 million is not until June 2024.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.9 billion at September 30, 2020, down from $2.0 billion at June 30, 2020. Based on the forward strip, we expect to maintain our financial liquidity and remain onside with our financial covenants.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at September 30, 2020.

Covenant Description	Position as at September 30, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	1.1:1.0	3.5:1.0
Interest Coverage(3) (Minimum Ratio)	5.4:1.0	2.0:1.0

Notes:

(1) Senior Secured Debt is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at September 30, 2020, the Company's Senior Secured Debt totaled $640.3 million which includes $624.8 million of principal amounts outstanding and $15.5 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expense, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expense, impairment, deferred income tax expense or recovery, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2020 was $566.1 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended September 30, 2020 was $105.2 million.

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. The following table summarizes our crude oil hedges in place.

	Q4/2020	2021
WTI Fixed Hedges		
Volumes (bbl/d)	8,000	---
Fixed Price (US$/bbl)	$42.78	---
WTI 3-Way Option (1)		
Volumes (bbl/d)	24,500	13,500
Baytex Receives (2) (3) (4)	WTI plus US$7.60	US$45
Total Volumes (bbl/d)	32,500	13,500

Notes:

(1) WTI 3-way options consist of a sold put, a bought put and a sold call. Baytex's average sold put, bought put and sold call for Q4/2020 are US$50.44/bbl, US$58.04/bbl and US$63.06/bbl, respectively. Baytex's average sold put, bought put and sold call for 2021 are US$35/bbl, US$45/bbl and US$53.57/bbl, respectively.

(2) For Q4/2020, Baytex receives WTI plus US$7.60/bbl when WTI is at or below US$50.44/bbl; Baytex receives US$58.04/bbl when WTI is between US$50.44/bbl and US$58.04/bbl; Baytex receives WTI when WTI is between US$58.04/bbl and US$63.06/bbl; and Baytex receives US$63.06/bbl when WTI is above US$63.06/bbl.

(3) For 2021, Baytex receives WTI plus US$10/bbl when WTI is at or below US$35/bbl; Baytex receives US$45/bbl when WTI is between US$35/bbl and US$45/bbl; Baytex receives WTI when WTI is between US$45/bbl and US$53.57; and Baytex receives US$53.57/bbl when WTI is above US$53.57/bbl.

(4) Based on the forward strip for the balance of 2020, Baytex will receive WTI plus US$7.60/bbl. Based on the forward strip for 2021, Baytex will receive US$45/bbl.

For Q4/2020, we also have WTI-MSW basis differential swaps for 5,000 bbl/d of our light oil production in Canada at US$6.15/bbl and WCS differential hedges on 6,500 bbl/d at a WTI-WCS differential of US$16.27/bbl.

We also have WTI-MSW differential hedges on approximately 40% of our expected 2021 Canadian light oil production at US$5.17/bbl and WCS differential hedges on approximately 45% of our expected 2021 heavy oil production at a WTI-WCS differential of approximately US$13.50/bbl.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q3/2020 financial statements.

Board Appointment

The Board of Directors is pleased to announce the appointment of Steve Reynish as a director of Baytex.

“We are very pleased that Steve has joined the Baytex board. His strategic perspective and tremendous breadth of experience across technology, ESG, marketing, and corporate development will serve the board and Baytex well in the years ahead,” commented Mark Bly, Chairman of Baytex.

Mr. Reynish is currently the President and Chief Executive Officer of Enlighten Innovations, a private Calgary based clean energy technology organization which he joined in 2020. Immediately prior to Enlighten Mr. Reynish served as an Executive Vice President at Suncor Energy Inc. for eight years in a variety of capacities where he was accountable for the company’s strategy, ESG and corporate development initiatives, new technology development, joint venture and commercial portfolios - all instrumental in positioning Suncor as a top-tier Western Canadian based integrated energy company. Prior to Suncor, Mr. Reynish served as President of Marathon Oil Canada, which he joined through the acquisition of Western Oil Sands where he was Executive Vice President, Operations. Prior to his entry into Canada, he held senior positions within the Anglo American Group, including Vice President of Mining of Anglo Base Metals in Johannesburg and Chief Executive Officer of Bindura Nickel in Zimbabwe. Mr. Reynish holds a Masters degree in Mining Engineering and an MBA, both earned in the UK. He has completed Post Graduate studies at IMD and the Wharton School. He is a member of the board of Energy Safety Canada, the Institute of Corporate Directors (ICD) and National Association of Corporate Directors (NCAD), and a former Member of the Board of Governors of the Oxford Institute of Energy Studies, the Canadian Associated of Petroleum Produces (CAPP) and the Canada Institute.

NYSE Delisting

On March 24, 2020 we received notice from the New York Stock Exchange (“NYSE”) that Baytex was no longer in compliance with one of the NYSE’s continued listing standards because the average closing price of Baytex’s common shares was less than US$1.00 per share over a consecutive 30 trading period. At this time, Baytex has not regained compliance and expects that its common shares will be delisted from the NYSE on December 3, 2020. This will not affect Baytex’s business operations and will not affect the continued listing and trading of Baytex’s common shares on the Toronto Stock Exchange. Currently, over 80% of the daily trading in Baytex common shares occurs in Canada, ensuring investors will retain significant trading liquidity going forward. In addition, Baytex expects to realize significant cost savings over time as a result of the delisting.

DRIP Termination

Baytex is formally terminating its dividend reinvestment plan (“DRIP”). All participants (as defined in the DRIP) effective as of the termination date, will be issued a certificate for any common shares and a cheque for any cash balance remaining in the participants’ account pursuant to the terms of the plan.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2020 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. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, November 3, 2020, starting at 9:00am MST (11:00am EST). 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/baytexq320201103.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; our guidance for 2020 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; that we are focused on further efficiencies to capture and sustain cost reductions while protecting the health and safety of our personnel; our drilling plans in Canada; that we plan to release our 2021 capital budget in December of 2020; that we have a production base of ~75,000 boe/d and a fully funded sustaining capital program at US$40 to US$45/bbl WTI; that we expect to bring 16 net wells on production in the Eagle Ford in 2020 and execute a 30 well program in the Viking in Q4/2020; that we have confirmed visibility to a $7.0 million well cost in the Duvernay; that we have de-risked our approximately 38-kilometer acreage fairway in the Pembina Duvernay; that we expect to maintain our financial liquidity and remain onside our financial covenants based on the forward strip; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility and the percentage of our expected production in 2021 of Canadian light oil and heavy oil for which we have hedged the differential to WTI; that we expect to be delisted from the NSYE on December 3rd, 2020, that we do not expect the delisting to affect our business operations or the listing and trading of our common shares on the TSX, that the TSX will provide investors significant trading liquidity and that we expect to realize significant cost savings.

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); availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; 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; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; 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 associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; 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; 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, 2019, 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.

<u>Non-GAAP Financial and Capital Management Measures</u>

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, 2020.

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.

<u>Advisory Regarding Oil and Gas Information</u>

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, 2020. 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, 2020					Nine Months Ended September 30, 2020				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	9,729	3	5	14,277	12,117	9,495	6	11	11,071	11,357
Lloydminster	12,409	12	—	1,518	12,674	11,451	13	—	1,280	11,677
Canada - Light										
Viking	—	16,943	105	10,357	18,774	—	19,047	108	11,398	21,054
Duvernay	—	710	457	1,840	1,474	—	690	385	1,535	1,330
Remaining Properties	—	580	714	16,988	4,125	—	653	674	17,743	4,284
United States										
Eagle Ford	—	15,853	6,136	39,965	28,650	—	19,161	6,446	45,574	33,203
Total	22,138	34,101	7,417	84,945	77,814	20,946	39,570	7,624	88,602	82,907

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 82% 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 and the New York Stock Exchange under the symbol BTE.BC.

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

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