BAYTEX
ENERGY CORP.

BAYTEX ANNOUNCES SECOND QUARTER 2020 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (July 29, 2020) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and six months ended June 30, 2020 (all amounts are in Canadian dollars unless otherwise noted).

“During the second quarter we took decisive steps to adjust our business model in the face of extremely volatile crude oil markets. We are now starting to benefit from the actions we have taken as we generated positive free cash flow during the quarter and maintained approximately $300 million of financial liquidity. We restarted approximately 80% of the previously announced shut-in volumes, which we expect will positively impact our adjusted funds flow for the remainder of the year,” commented Ed LaFehr, President and Chief Executive Officer.

Q2 2020 Highlights

- Generated production of 72,508 boe/d (81% oil and NGL), consistent with our previously announced guidance range for the second quarter of 72,000 to 73,000 boe/d.
- Delivered adjusted funds flow of $18 million ($0.03 per basic share).
- Realized an operating netback (inclusive of realized financial derivatives gain) of $8.02/boe.
- Reduced net debt by $57 million as the Canadian dollar strengthened relative to the U.S. dollar and we generated positive free cash flow of $6 million.
- Maintained undrawn credit capacity of $363 million and liquidity, net of working capital, of approximately $300 million.
- Achieved a 15% reduction in our GHG emissions intensity in 2019 and remain committed to our 30% target by the end of 2021.

2020 Outlook

We continue to forecast annual capital spending of $260 to $290 million, an approximate 50% reduction from our original plan of $500 to $575 million. With this revised capital program, we suspended drilling operations in Canada and moderated the pace of activity in the Eagle Ford.

We previously announced voluntary production shut-ins of approximately 25,000 boe/d. These volumes remained off-line for April and May. As operating netbacks improved in June, we initiated plans to bring approximately 80% of these volumes back on-line. At current commodity prices, the resumption of production from these previously shut-in barrels is expected to have a positive impact on our adjusted funds flow and improve our financial liquidity. For the second half of 2020, we currently project about 5,000 boe/d of heavy oil production to remain shut-in.

On June 25, we revised our production guidance range for 2020 to 78,000 to 82,000 boe/d, from 70,000 to 74,000 boe/d previously, taking into account the production brought back on-line. Should operating netbacks change, we have the ability to shut-in additional volumes or restart wells in short order.

We remain intensely focused on driving further efficiencies to capture or sustain cost reductions identified during this downturn, while protecting the health and safety of our personnel.

	Three Months Ended			Six Months Ended	
	June 30, 2020	March 31, 2020	June 30, 2019	**June 30, 2020**	June 30, 2019
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 152,689**	$ 336,614	$ 482,000	**$ 489,303**	$ 935,424
Adjusted funds flow [1]	**17,887**	132,935	236,130	**150,822**	456,900
Per share - basic	**0.03**	0.24	0.42	**0.27**	0.82
Per share - diluted	**0.03**	0.24	0.42	**0.27**	0.82
Net income (loss)	**(138,463)**	(2,498,217)	78,826	**(2,636,680)**	90,162
Per share - basic	**(0.25)**	(4.46)	0.14	**(4.71)**	0.16
Per share - diluted	**(0.25)**	(4.46)	0.14	**(4.71)**	0.16
Capital Expenditures					
Exploration and development expenditures [1]	**$ 9,852**	$ 176,777	$ 106,246	**$ 186,629**	$ 260,089
Acquisitions, net of divestitures	**(11)**	(40)	1,647	**(51)**	1,647
Total oil and natural gas capital expenditures	**$ 9,841**	$ 176,737	$ 107,893	**$ 186,578**	$ 261,736
Net Debt					
Bank loan [2]	**$ 704,135**	$ 678,740	$ 414,691	**$ 704,135**	$ 414,691
Long-term notes [2]	**1,225,395**	1,270,800	1,543,645	**1,225,395**	1,543,645
Long-term debt	**1,929,530**	1,949,540	1,958,336	**1,929,530**	1,958,336
Working capital deficiency	**65,423**	102,077	70,350	**65,423**	70,350
Net debt [1]	**$ 1,994,953**	$ 2,051,617	$ 2,028,686	**$ 1,994,953**	$ 2,028,686
Shares Outstanding - basic (thousands)					
Weighted average	**560,512**	559,804	556,599	**560,158**	556,022
End of period	**560,545**	560,483	556,798	**560,545**	556,798
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 27.85**	$ 46.17	$ 59.81	**$ 37.01**	$ 57.36
MEH oil (US$/bbl)	**26.40**	49.54	66.37	**37.97**	63.42
MEH oil differential to WTI (US$/bbl)	**(1.45)**	3.37	6.56	**0.96**	6.06
Edmonton par ($/bbl)	**29.85**	51.43	73.84	**40.64**	70.19
Edmonton par differential to WTI (US$/bbl)	**(6.31)**	(7.92)	(4.61)	**(7.24)**	(4.72)
WCS heavy oil ($/bbl)	**22.70**	34.48	65.73	**28.68**	61.17
WCS differential to WTI (US$/bbl)	**(11.47)**	(20.53)	(10.68)	**(16.00)**	(11.48)
Natural gas					
NYMEX (US$/mmbtu)	**$ 1.72**	$ 1.95	$ 2.64	**$ 1.83**	$ 2.89
AECO ($/mcf)	**1.91**	2.14	1.17	**2.03**	1.56
CAD/USD average exchange rate	**1.3860**	1.3445	1.3376	**1.3653**	1.3334

	Three Months Ended			Six Months Ended	
	June 30, 2020	March 31, 2020	June 30, 2019	**June 30, 2020**	June 30, 2019
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**38,951**	45,717	42,585	**42,333**	43,809
Heavy oil (bbl/d)	**11,832**	28,854	27,320	**20,343**	27,107
NGL (bbl/d)	**7,634**	7,822	10,986	**7,728**	11,356
Total liquids (bbl/d)	**58,417**	82,393	80,891	**70,404**	82,272
Natural gas (mcf/d)	**84,546**	96,356	105,065	**90,451**	104,874
Oil equivalent (boe/d @ 6:1) (3)	**72,508**	98,452	98,402	**85,479**	99,751
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 147,229**	$ 315,257	$ 461,110	**$ 462,486**	$ 897,746
Royalties	**(29,156)**	(56,720)	(86,617)	**(85,876)**	(167,942)
Operating expense	**(73,680)**	(104,470)	(100,474)	**(178,150)**	(200,766)
Transportation expense	**(5,031)**	(10,342)	(11,869)	**(15,373)**	(25,199)
Operating netback (1)	**$ 39,362**	**$ 143,725**	**$ 262,150**	**$ 183,087**	**$ 503,839**
General and administrative	**(7,438)**	(9,775)	(11,506)	**(17,213)**	(25,642)
Cash financing and interest	**(27,387)**	(28,535)	(28,092)	**(55,922)**	(56,276)
Realized financial derivatives gain	**13,624**	26,850	12,993	**40,474**	31,807
Other (5)	**(274)**	670	585	**396**	3,172
Adjusted funds flow (1)	**$ 17,887**	**$ 132,935**	**$ 236,130**	**$ 150,822**	**$ 456,900**
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 22.31**	$ 35.19	$ 51.49	**$ 29.73**	$ 49.72
Royalties	**(4.42)**	(6.33)	(9.67)	**(5.52)**	(9.30)
Operating expense	**(11.17)**	(11.66)	(11.22)	**(11.45)**	(11.12)
Transportation expense	**(0.76)**	(1.15)	(1.33)	**(0.99)**	(1.40)
Operating netback (1)	**$ 5.96**	**$ 16.05**	**$ 29.27**	**$ 11.77**	**$ 27.90**
General and administrative	**(1.13)**	(1.09)	(1.28)	**(1.11)**	(1.42)
Cash financing and interest	**(4.15)**	(3.19)	(3.14)	**(3.59)**	(3.12)
Realized financial derivatives gain	**2.06**	3.00	1.45	**2.60**	1.76
Other (5)	**(0.03)**	0.07	0.07	**0.02**	0.19
Adjusted funds flow (1)	**$ 2.71**	**$ 14.84**	**$ 26.37**	**$ 9.69**	**$ 25.31**

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 bank loan 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, and current income tax expense or recovery. Refer to the Q2/2020 MD&A for further information on these amounts.

Q2/2020 Results

During the second quarter we took decisive steps to adjust our business plan in the face of extremely volatile crude oil markets. In addition to voluntarily shutting-in production, we suspended drilling operations in Canada and moderated our pace of activity in the Eagle Ford. As a result, exploration and development spending totaled a modest $10 million during the second quarter.

Production during the second quarter averaged 72,508 boe/d (81% oil and NGL), as compared to 98,452 boe/d (83% oil and NGL) in Q1/2020. Production in Canada averaged 37,691 boe/d (83% oil and NGL), as compared to 62,262 boe/d in Q1/2020, while production in the Eagle Ford averaged 34,817 boe/d (77% oil and NGL), as compared to 36,190 boe/d in Q1/2020. Our second quarter production was reduced by approximately 20,000 boe/d due to the voluntary shut-ins.

We delivered adjusted funds flow of $18 million ($0.03 per basic share) in Q2/2020 and generated an operating netback of $5.96/boe ($8.02/boe inclusive of realized financial derivatives gain). The Eagle Ford generated an operating netback of $10.05/boe and our Canadian operations generated an operating netback of $2.19/boe.

We continue to emphasize cost reductions across all facets of our organization. We have identified approximately $98 million of cost reductions for 2020 (operating, transportation and general & administrative expenses). During the second quarter, our operating expense of $11.17/boe compared favorably to $11.66/boe in Q1/2020 as we strive to mitigate the costs associated with our field operations. In addition, we realized an approximate 35% reduction in our per boe transportation expense due to reduced volumes. General and administrative expense totaled $7.4 million ($1.13/boe) in Q2/2020, down from $9.8 million ($1.09/boe) in Q1/2020 as we implemented reductions to salaries and annual retainers and benefited from the Canadian Emergency Wage Subsidy.

Eagle Ford and Viking Light Oil

In the Eagle Ford, strong well performance continued across our acreage position. In Q2/2020, we commenced production from 17 (4.6 net) wells. These wells were brought on-stream in April and generated an average 30-day initial production rate of approximately 1,550 boe/d per well. We expect to bring approximately 16 to 18 net wells on production in the Eagle Ford in 2020, down from our original guidance of 22 net wells.

Production in the Viking averaged 19,717 boe/d (90% oil and NGL) during Q2/2020, as compared to 24,696 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins in the Viking was approximately 2,000 boe/d. As operating netbacks improved in June, these volumes were brought back on-line. We suspended all drilling in the Viking, and as such, there was limited activity during the second quarter. In the first half of 2020, we invested $79 million on exploration and development in the Viking and commenced production from 83 (78.5 net) wells.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 13,082 boe/d (91% oil and NGL) during the second quarter, as compared to 31,211 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins for heavy oil was approximately 17,000 boe/d. We suspended all heavy oil drilling, and as such, there was limited activity during the second quarter. In the first half of 2020, we invested $40 million on exploration and development and drilled 33 (33.0 net) wells. For the second half of 2020, we currently project about 5,000 boe/d of heavy oil production to remain shut-in.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 717 boe/d (85% oil and NGL) during Q2/2020, as compared to 1,717 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins for the Pembina Duvernay was approximately 1,000 boe/d. As operating netbacks improved in June, these volumes were brought back on-line.

In Q1/2020, we drilled two wells in the core of our Pembina acreage, bringing total wells drilled to nine in this area. Completion activities, originally scheduled for Q2/2020 have been deferred.

Financial Liquidity

Our credit facilities total approximately $1.1 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 June 30, 2020, we had $363 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of approximately $300 million. In addition, our first long-term note maturity of US$400 million is not until June 2024.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.0 billion at June 30, 2020. Based on the forward strip(1), we expect to maintain our financial liquidity and remain onside with our financial covenants through 2021.

Note:

(1) 2020 full year pricing assumptions: WTI - US$39/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$1.90/mcf; AECO Gas - $2.05/mcf and Exchange Rate (CAD/USD) - 1.36. 2021 full year pricing assumptions: WTI - US$41/bbl; WCS differential - US$15/bbl; MSW differential – US$7/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $2.35/mcf and Exchange Rate (CAD/USD) - 1.36.

Financial Covenants

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

Covenant Description	Position as at June 30, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	1.0:1.0	3.5:1.0
Interest Coverage(3) (Minimum Ratio)	6.6:1.0	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 June 30, 2020, the Company's Senior Secured Debt totaled $719.9 million which includes $704.1 million of principal amounts outstanding and $15.8 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 June 30, 2020 was $704.4 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 June 30, 2020 was $106.5 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.

	Q3/2020	Q4/2020	2021
WTI Fixed Hedges			
Volumes (bbl/d)	23,732	8,000	---
Fixed Price (US$/bbl)	$36.41	$42.78	---
WTI 3-Way Option (1)			
Volumes (bbl/d)	24,500	24,500	5,000
Baytex Receives (2) (3) (4)	WTI plus US$7.60	WTI plus US$7.60	US$45/bbl
Total Volumes (bbl/d)	48,232	32,500	5,000

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 Q3/2020 and 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$55/bbl, respectively.
(2) For Q3/2020 and 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$55/bbl; and Baytex receives US$55/bbl when WTI is above US$55/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 the remainder of 2020, we also have WTI-MSW basis differential swaps for 7,783 bbl/d of our light oil production in Canada at US$5.80/bbl and WCS differential hedges on 8,667 bbl/d at a WTI-WCS differential of US$14.57/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For Q2/2020, we delivered approximately 5,250 bbl/d of our heavy oil volumes to market by rail.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2020 financial statements.

Sustainability

We are committed to managing the environmental and social impacts of our business and continual improvement is an important element of this commitment. In 2019, Baytex established for the first time a GHG emissions reduction target. Our objective is to reduce our corporate GHG emission intensity (tonnes of CO2 per boe) by 30% by 2021, relative to our 2018 baseline.

In 2019, we made significant improvements in our emissions profile, achieving a 15% reduction in our GHG emissions intensity as we commissioned our Peace River gas plant in mid-2018 and progressed our Viking gas conservation project. We remain committed to achieving our 30% target by the end of 2021.

2020 Guidance

There is no change to our guidance announced June 25, 2020.

	2020 Guidance
Exploration and development expenditures	$260 - $290 million
Production (boe/d)	78,000 - 82,000
Expenses:	
Royalty rate	~ 18.5%
Operating	$11.75 - $12.50/boe
Transportation	$0.95 - $1.05/boe
General and administrative	$38 million ($1.30/boe)
Interest	$112 million ($3.84/boe)
Leasing expenditures	$7 million
Asset retirement obligations	$10 million

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 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. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, July 30, 2020, 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/baytexq220200730.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; restarted shut-in volumes will have a positive impact on our adjusted funds flow; that the resumption of production from shut-in barrels is expected to positively impact adjusted funds flow and improve financial liquidity; our ability to re-start shut in wells or shut-in additional volumes; we expect 5,000 boe/d of heavy oil to remain shut-in for H2/2020; we are focused on further efficiencies to capture or sustain cost reduction while protecting the health and safety of our personnel; that we have identified $98 million of cost reductions for 2020 and continue to emphasize cost reductions; the number of Eagle Ford wells we expect to bring online in 2020; that we expect to maintain our financial liquidity and remain onside our financial covenants through 2021; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; that we are committed to managing the environmental and social impacts of our business; that we are committed to achieving our 30% emissions intensity target; and 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.

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.

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 six months ended June 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 bank loan. 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 bank loan 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 bank loan 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 six months ended June 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 June 30, 2020					**Six Months Ended June 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	4,735	6	15	6,278	5,802	9,377	7	14	9,450	10,973
Lloydminster	7,098	10	—	1,039	7,281	10,966	14	—	1,160	11,174
Canada - Light										
Viking	—	17,735	105	11,267	19,717	—	20,110	109	11,925	22,206
Duvernay	—	430	176	670	717	—	680	348	1,381	1,258
Remaining Properties	—	581	638	17,728	4,174	—	690	654	18,124	4,365
United States										
Eagle Ford	—	20,189	6,701	47,564	34,817	—	20,832	6,603	48,410	35,503
Total	11,832	38,951	7,634	84,546	72,508	20,343	42,333	7,728	90,451	85,479

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 83% of Baytex's production is weighted toward crude oil and natural gas liquids. 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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