BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2019 FINANCIAL AND OPERATING RESULTS AND BOARD APPOINTMENT

CALGARY, ALBERTA (March 4, 2020) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2019 (all amounts are in Canadian dollars unless otherwise noted).

"2019 was an exceptional year with $1 billion EBITDA, $329 million of free cash flow and a 17% reduction in net debt. During the first quarter of 2020, we enhanced our long-term note maturity schedule and extended the term of our revolving credit facilities to 2024. Our operations continue to perform well with strong capital efficiencies in each of our core properties (Eagle Ford, Viking and Heavy Oil). Together, these measures give us confidence and significant flexibility to execute our business plan to continue driving free cash flow and strengthening our balance sheet," commented Ed LaFehr, President and Chief Executive Officer.

2019 Highlights

We released preliminary unaudited financial and operating results on January 20, 2020 in conjunction with the release of our 2019 reserves. Our audited financial and operating results for the three months and year ended December 31, 2019 are unchanged from the preliminary results.

- Generated production of 96,360 boe/d (83% oil and NGL) during Q4/2019 and 97,680 boe/d for full-year 2019, exceeding the high end of guidance.
- Exploration and development expenditures totaled $153 million in Q4/2019, bringing aggregate spending for 2019 to $552 million, which is at the low end of our original guidance.
- Delivered adjusted funds flow of $232 million ($0.42 per basic share) in Q4/2019 and $902 million ($1.62 per basic share) for 2019.
- Generated EBITDA of $256 million in Q4/2019 and $1.01 billion for 2019.
- Reduced net debt by $100 million in Q4/2019 and by $393 million in 2019 with free cash flow along with a strengthening of the Canadian dollar relative to the U.S. dollar. Net debt totaled $1.87 billion at December 31, 2019.
- Achieved a strong year of reserves development with proved developed producing reserves increasing 5% with finding & development costs of $13.04/boe and a recycle ratio of 2.3x.

Bond Refinancing and Bank Credit Extension

- On February 6, 2020, we issued US$500 million principal amount of 8.75% senior unsecured notes due April 1, 2027. Net proceeds have been used to redeem US$400 million principal amount of 5.125% senior unsecured notes due 2021. We also called for redemption $300 million principal amount of 6.625% senior unsecured notes due 2022 on March 6, 2020.
- On March 3, 2020, we extended the maturity of our revolving credit facilities and term loan to April 2, 2024 (from June 4, 2021). The credit facilities total approximately $1,046 million and do not require annual or semi-annual reviews.

2020 Outlook

Our 2020 guidance remains unchanged as we target production of 93,000 to 97,000 boe/d with exploration and development expenditures of $500 to $575 million. Our exploration and development program is expected to be fully funded from adjusted funds flow at the forward strip(1) and we have the operational flexibility to adjust our spending plans based on changes in commodity prices. For 2020, we have entered into hedges on approximately 48% of our net crude oil exposure, largely utilizing a 3-way option structure that provides WTI price protection at US$58.04/bbl.

(1) 2020 full-year pricing assumptions: WTI - US$48.64/bbl; LLS - US$51.39/bbl; WCS differential - US$16.15/bbl; MSW differential – US$5.51/bbl, NYMEX Gas - US$1.97/mcf; AECO Gas - $1.79/mcf and Exchange Rate (CAD/USD) - 1.336.

	Three Months Ended			Years Ended	
	December 31, 2019	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 445,895**	$ 424,600	$ 358,437	**$ 1,805,919**	$ 1,428,870
Adjusted funds flow (1)	**232,147**	213,379	110,828	**902,426**	472,983
Per share – basic	**0.42**	0.38	0.20	**1.62**	1.35
Per share – diluted	**0.42**	0.38	0.20	**1.62**	1.35
Net income (loss)	**(117,772)**	15,151	(231,238)	**(12,459)**	(325,309)
Per share – basic	**(0.21)**	0.03	(0.42)	**(0.02)**	(0.93)
Per share – diluted	**(0.21)**	0.03	(0.42)	**(0.02)**	(0.93)
Capital Expenditures					
Exploration and development expenditures (1)	**$ 153,117**	$ 139,085	$ 184,162	**$ 552,291**	$ 495,721
Acquisitions, net of divestitures	**563**	(30)	229	**2,180**	1,603,850
Total oil and natural gas capital expenditures	**$ 153,680**	$ 139,055	$ 184,391	**$ 554,471**	$ 2,099,571
Net Debt					
Bank loan (2)	**$ 506,471**	$ 570,792	$ 522,294	**$ 506,471**	$ 522,294
Long-term notes (2)	**1,337,200**	1,359,480	1,596,323	**1,337,200**	1,596,323
Long-term debt	**1,843,671**	1,930,272	2,118,617	**1,843,671**	2,118,617
Working capital deficiency	**28,120**	41,067	146,550	**28,120**	146,550
Net debt (1)	**$ 1,871,791**	$ 1,971,339	$ 2,265,167	**$ 1,871,791**	$ 2,265,167
Shares Outstanding - basic (thousands)					
Weighted average	**558,228**	557,888	554,036	**557,048**	351,542
End of period	**558,305**	557,972	554,060	**558,305**	554,060
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 56.96**	$ 56.45	$ 58.81	**$ 57.03**	$ 64.77
LLS (US$/bbl)	**60.73**	61.88	66.64	**62.84**	70.09
LLS differential to WTI (US$/bbl)	**3.77**	5.43	7.83	**5.81**	5.32
Edmonton par ($/bbl)	**68.10**	68.41	42.68	**69.22**	69.31
Edmonton par differential to WTI (US$/bbl)	**(5.37)**	(4.66)	(26.51)	**(4.86)**	(11.30)
WCS heavy oil ($/bbl)	**54.29**	58.39	25.62	**58.75**	49.85
WCS differential to WTI (US$/bbl)	**(15.83)**	(12.24)	(39.42)	**(12.75)**	(26.31)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.50**	$ 2.23	$ 3.64	**$ 2.63**	$ 3.09
AECO ($/mcf)	**2.34**	1.04	1.94	**1.62**	1.54
CAD/USD average exchange rate	**1.3201**	1.3207	1.3215	**1.3269**	1.2962

	Three Months Ended			Years Ended	
	December 31, 2019	September 30, 2019	December 31, 2018	**December 31, 2019**	December 31, 2018
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**43,906**	42,829	44,987	**43,587**	29,264
Heavy oil (bbl/d)	**27,050**	25,712	26,339	**26,741**	25,954
NGL (bbl/d)	**8,699**	9,543	10,327	**10,229**	9,745
Total liquids (bbl/d)	**79,655**	78,084	81,653	**80,557**	64,963
Natural gas (mcf/d)	**100,235**	101,054	103,424	**102,742**	92,971
Oil equivalent (boe/d @ 6:1) (3)	**96,360**	94,927	98,890	**97,680**	80,458
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 427,728**	$ 411,650	$ 344,682	**$ 1,737,124**	$ 1,360,038
Royalties	**(77,282)**	(75,017)	(79,765)	**(320,241)**	(313,754)
Operating expense	**(99,573)**	(97,377)	(97,857)	**(397,716)**	(311,592)
Transportation expense	**(8,840)**	(9,903)	(10,994)	**(43,942)**	(36,869)
Operating netback (1)	**$ 242,033**	$ 229,353	$ 156,066	**$ 975,225**	$ 697,823
General and administrative	**(9,893)**	(9,934)	(14,096)	**(45,469)**	(45,825)
Cash financing and interest	**(24,389)**	(26,752)	(27,933)	**(107,417)**	(104,318)
Realized financial derivatives gain (loss)	**22,956**	20,857	(3,063)	**75,620**	(73,165)
Other (5)	**1,440**	(145)	(146)	**4,467**	(1,532)
Adjusted funds flow (1)	**$ 232,147**	$ 213,379	$ 110,828	**$ 902,426**	$ 472,983
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 48.25**	$ 47.14	$ 37.89	**$ 48.72**	$ 46.31
Royalties	**(8.72)**	(8.59)	(8.77)	**(8.98)**	(10.68)
Operating expense	**(11.23)**	(11.15)	(10.76)	**(11.16)**	(10.61)
Transportation expense	**(1.00)**	(1.13)	(1.21)	**(1.23)**	(1.26)
Operating netback (1)	**$ 27.30**	$ 26.27	$ 17.15	**$ 27.35**	$ 23.76
General and administrative	**(1.12)**	(1.14)	(1.55)	**(1.28)**	(1.56)
Cash financing and interest	**(2.75)**	(3.06)	(3.07)	**(3.01)**	(3.55)
Realized financial derivatives gain (loss)	**2.59**	2.39	(0.34)	**2.12**	(2.49)
Other (5)	**0.16**	(0.03)	(0.02)	**0.13**	(0.05)
Adjusted funds flow (1)	**$ 26.18**	$ 24.43	$ 12.17	**$ 25.31**	$ 16.11

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, current income tax expense or recovery and payments on onerous contracts. Refer to the 2019 MD&A for further information on these amounts.

Operating Results

Our 2019 operating and financial results demonstrate the benefits of our diversified oil weighted portfolio and our commitment to allocate capital effectively, generate free cash flow and further strengthen our balance sheet.

Our production exceeded the high end of our annual guidance with outstanding capital efficiencies in our development program and each of our core properties (Eagle Ford, Viking and Heavy Oil) generated an operating netback in excess of exploration and development expenditures. We also achieved a strong year of reserves development with proved developed producing reserves increasing 5% with finding & development costs of $13.04/boe and a recycle ratio of 2.3x.

Production during the fourth quarter averaged 96,360 boe/d (83% oil and NGL), as compared to 94,927 boe/d (82% oil and NGL) in Q3/2019. Production in 2019 averaged 97,680 boe/d as compared to 80,458 boe/d in 2018. Exploration and development expenditures totaled $153 million in Q4/2019 and $552 million for full-year 2019. We participated in the completion of 417 (313.9 net) wells with a 99% success rate during the year.

The following table compares our 2019 results to our 2019 original budget guidance.

	2019 Original Guidance (1)	2019 Results
Exploration and development expenditures	$550 - $650 million	$552.3 million
Production (boe/d)	93,000 - 97,000	97,680
Expenses:		
Royalty rate	20.0%	18.4%
Operating	$10.75 - $11.25/boe	$11.16/boe
Transportation	$1.25 - $1.35/boe	$1.23/boe
General and administrative	~ $46 million ($1.30/boe)	$45.5 million ($1.28/boe)
Interest	~ $112 million ($3.23/boe)	$107.4 million ($3.01/boe)
Leasing expenditures	$5 million	$6 million
Asset retirement obligations	$17 million	$15 million

Note:

(1) As announced on December 17, 2018. Includes updated guidance on May 2, 2019 for general and administrative expenses and leasing expenditures to reflect a change associated with the adoption of IFRS 16.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 38,567 boe/d (78% oil and NGL) during Q4/2019, as compared to 36,793 boe/d in Q3/2019. Production for 2019 averaged 39,055 boe/d, as compared to 37,076 boe/d in 2018. In 2019, we invested $178 million on exploration and development in the Eagle Ford and generated an operating netback of $416 million.

In the Eagle Ford, we continued to see strong well performance driven by enhanced completions across our acreage position. In 2019, we participated in the drilling of 96 (20.2 net) wells and commenced production from 109 (25.1 net) wells. The wells brought on-stream during 2019 generated an average 30-day initial production rate of approximately 1,900 boe/d per well, which represents an approximate 8% improvement over wells brought on-stream in 2018.

Production in the Viking averaged 22,050 boe/d (91% oil and NGL) during Q4/2019, as compared to 22,198 boe/d in Q3/2019. Production for the full-year 2019 averaged 22,546 boe/d. In 2019, we invested $266 million on exploration and development in the Viking and generated an operating netback of $349 million.

In the Viking, we maintained an active pace of development in 2019, drilling 275 (243.6 net) wells and commencing production from 271 (239.7 net) wells. In 2019, over 90% of our drilling program was extended reach horizontal wells. We also added 229 net high quality drilling opportunities through multiple deals and asset swaps.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 29,707 boe/d (91% oil and NGL) during the fourth quarter, as compared to 28,483 boe/d in Q3/2019. We drilled 40 (40.0 net) heavy oil wells in 2019, including 34 net wells at Lloydminster and six net wells at Peace River. In 2019, we invested $80 million on exploration and development on our heavy oil assets and generated an operating netback of $188 million.

East Duvernay Shale Light Oil

We continue to advance the delineation of the East Duvernay Shale, an early stage, high operating netback light oil resource play. As of December 31, 2019, we have drilled seven wells at Pembina, confirming the prospectivity of our acreage. Two wells brought on-stream in 2019 generated an average 30-day initial production rate of approximately 1,050 boe/d per well (75% oil and NGL) and are in the top 15% of all wells drilled to date in the play.

In Q1/2020, we drilled two wells at Pembina and completion activities are scheduled for Q2/2020. The success of our drilling program in the Pembina area has significantly de-risked our approximately 38 kilometer long acreage fairway, where we hold 275 sections (100% working interest) of Duvernay land.

Financial Review

We delivered adjusted funds flow of $232 million ($0.42 per basic share) in Q4/2019 and $902 million ($1.62 per basic share) in 2019. This resulted in free cash flow of $73 million in Q4/2019 and $329 million in 2019. This strong free cash flow, along with the Canadian dollar strengthening relative to the U.S. dollar, contributed to a 17% reduction in our net debt this year.

We recorded a net loss of $118 million ($0.21 per basic share) in Q4/2019 and $12 million ($0.02 per basic share) in 2019. The net loss is attributable to a non-cash impairment charge of $188 million on our heavy oil assets and reflects lower heavy oil prices and a change in development plan for our thermal projects at Peace River.

We realized an operating netback of $27.30/boe in Q4/2019, as compared to $26.27/boe in Q3/2019 and $17.15/boe in Q4/2018. Including financial derivatives, our operating netback improved to $29.89/boe, as compared to $16.81/boe in Q4/2018. Our Canadian operations generated an operating netback of $24.72/boe during Q4/2019 while our Eagle Ford asset generated an operating netback of $31.17/boe.

The following table summarizes our operating netbacks for the periods noted.

	Three Months Ended December 31					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**57,794**	**38,566**	**96,360**	60,453	38,437	98,890
Total sales, net of blending and other (1)	**$ 45.52**	**$ 52.33**	**$ 48.25**	$ 24.04	$ 59.66	$ 37,89
Royalties	**(4.73)**	**(14.69)**	**(8.72)**	(3.10)	(17.68)	(8.77)
Operating expense	**(14.41)**	**(6.47)**	**(11.23)**	(13.42)	(6.56)	(10.76)
Transportation expense	**(1.66)**	**—**	**(1.00)**	(1.98)	—	(1.21)
Operating netback (2)	**$ 24.72**	**$ 31.17**	**$ 27.30**	$ 5.54	$ 35.42	$ 17.15
Realized financial derivatives gain (loss)	**—**	**—**	**2.59**	—	—	(0.34)
Operating netback after financial derivatives	**$ 24.72**	**$ 31.17**	**$ 29.89**	$ 5.54	$ 35.42	$ 16.81

Notes:

(1) 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.

(2) The term "operating netback" does 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.

Balance Sheet and Liquidity

In 2019, we set a priority to further deleverage and strengthen our balance sheet. We delivered on this commitment as highlighted by the following key milestones:

- We generated free cash flow of $73 million in Q4/2019 and $329 million in 2019.
- We reduced net debt by $100 million in Q4/2019 and by $393 million in 2019 due to the strong free cash flow and a strengthening of the Canadian dollar relative to the U.S. dollar.
- We completed the early redemption of US$150 million principal amount of 6.75% senior unsecured notes due February 17, 2021 at par on September 13, 2019.

Subsequent to year-end, we further improved our financial position:

- We enhanced our long-term note maturity schedule which provides us significant flexibility and liquidity to execute our business plan.
  - On February 5, 2020, we issued US$500 million principal amount of 8.75% senior unsecured notes, which mature on April 1, 2027. These notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023.
  - On February 20, 2020, we redeemed US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 at par.
  - We issued a redemption notice for $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022 for redemption on March 6, 2020 at 101.104% of the principal amount.
  - Following these redemptions, our next long-term note maturity will be June 2024.
- We amended our credit facilities to extend the maturities of our revolving facilities and term loan to April 2, 2024. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. Our facilities total approximately $1,046 million and include US$575 million of revolving credit facilities and a $300 million term loan.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $1,872 million at December 31, 2019, down 17% from $2,265 million at December 31, 2018. Following the US$500 million note issue and the redemption of the US$400 million and $300 million notes, our credit facilities are approximately one-third undrawn, we retain over $300 million of liquidity and the weighted average interest rate on our long-term debt is approximately 6%.

Risk Management

To manage commodity price movements we utilize various financial derivative contracts and crude-by-rail to reduce the volatility in our adjusted funds flow. We realized a financial derivatives gain of $76 million in 2019, as compared to a loss of $73 million in 2018.

For 2020, we have entered into hedges on approximately 48% of our net crude oil exposure, largely utilizing a 3-way option structure on 24,500 bbl/d that provides WTI price protection at US$58.04/bbl with upside participation to US$63.06/bbl. The 3-way contracts are structured as follows:

WTI	Baytex Receives (1)
At or below US$50.44/bbl	WTI + US$7.60/bbl
Between US$50.44/bbl and US$58.04/bbl	US$58.04/bbl
Between US$58.04/bbl and US$63.06/bbl	WTI
Above US$63.06/bbl	US$63.06/bbl

Note:

(1) The price Baytex receives represents an average of all contracts entered into.

In addition to the 3-way options, we have WTI-based fixed price swaps on 3,500 bbl/d at US$57.40/bbl for 2020. We also have WTI-MSW basis differential swaps for 4,250 bbl/d of our light oil production in Canada at US$6.19/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2020, we are contracted to deliver approximately 11,500 bbl/d of our heavy oil volumes to market by rail. In addition, we have WCS differential hedges on 5,500 bbl/d at a WTI-WCS differential of US$16.25/bbl.

A complete listing of our financial derivative contracts can be found in Note 20 to our 2019 financial statements.

2020 Outlook

We have a high quality and diversified oil portfolio with a strong drilling inventory of approximately 10 or more years in each of our core areas (Viking, Eagle Ford and Heavy Oil). Our commitment remains to deliver stable production, generate free cash flow and further strengthen our balance sheet.

Our 2020 annual guidance remains unchanged as we target production of 93,000 to 97,000 boe/d with exploration and development expenditures of $500 to $575 million. For Q1/2020, production is trending above 97,000 boe/d with exploration and development expenditures of approximately $200 million, consistent with our plan and capital guidance range.

Our exploration and development program is expected to be fully funded from adjusted funds flow at the forward strip(1) and we have the operational flexibility to adjust our spending plans based on changes in commodity prices.

(1) 2020 full-year pricing assumptions: WTI - US$48.64/bbl; LLS - US$51.39/bbl; WCS differential - US$16.15/bbl; MSW differential – US$5.51/bbl, NYMEX Gas - US$1.97/mcf; AECO Gas - $1.79/mcf and Exchange Rate (CAD/USD) - 1.336.

The following table summarizes our 2020 annual guidance.

Exploration and development expenditures	$500 - $575 million
Production (boe/d)	93,000 to 97,000
Expenses:	
Royalty rate	18.0% - 18.5%
Operating	$11.25 - $12.00/boe
Transportation	$1.20 - $1.30/boe
General and administrative	$45 million ($1.30/boe)
Interest	$112 million ($3.23/boe)
Leasing expenditures	$7 million
Asset retirement obligations	$19 million

Board Appointment

The Board of Directors is pleased to announce the appointment of Don Hrap as a director of Baytex.

“We are very pleased that Don has joined the Baytex board. His business knowledge, strategic perspective and tremendous breadth of experience across U.S. and Canadian energy will serve the board and Baytex well in the years ahead,” commented Mark Bly, Chairman of Baytex.

Mr. Hrap has spent 35 years in the upstream oil and gas business, primarily holding executive positions in North America. From 2009-2018, he served as President, Lower 48 at ConocoPhillips with strong breadth and depth of experience across several U.S. oil resource plays. Prior to this at ConocoPhillips, Mr. Hrap was senior vice president of Western Canada Gas. He joined ConocoPhillips in 2006 through the merger with Burlington Resources, serving as senior vice president of operations for Burlington Canada. Earlier, he was vice president for the North American Division at Gulf Canada Resources, where he worked for 17 years. Mr. Hrap previously served as chairman of the API Upstream Committee, a Board member of the Independent Petroleum Association of America (IPAA) and a member of the U.S. Oil & Gas Association. He is also a Director of Tall City III Exploration LLC and WildFire Energy I LLC, and also serves as an Industry Advisor to Warburg Pincus. Mr. Hrap graduated from the University of Manitoba with a Bachelor of Science in Mechanical Engineering in 1982. In 1995, he graduated from the University of Calgary with a Master in Business Administration.

Baytex has an ongoing board renewal process led by its Nominating and Governance Committee. In the last year, we have significantly restructured our board. Throughout this renewal process, our intent has been to create an efficient board with complementary skill sets suited to our business, ensure independence and increase diversity.

Conference Call Today
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call today, March 4, 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/baytexq4ye20200304.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.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2019 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.

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 "anticipate", "believe", "continue", "could", "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 have flexibility to execute our business plan driving free cash flow and strengthening our balance sheet; our 2020 production and capital expenditure guidance; that our exploration and development program is expended to be fully funded by adjusted funds flow at a WTI price US$50/bbl; the percentage of our net crude oil exposure that is hedged for 2020; that we continue to advance the delineation of East Duvernay shale; our plan to complete two wells at Pembina in Q2/2020; that we have de-risked our 38 kilometer acreage fairway in Pembina; that our long-term note maturity schedule provides us significant flexibility and liquidity to execute our business plan; that after completing the announced redemption of long-term notes our credit facilities will be one-third undrawn, we will have over $300 million of liquidity and the weighted average cost of our debt will be approximately 6%; that we have a strong drilling inventory of approximately 10 or more years in each core area (Viking, Eagle Ford and Heavy Oil); we are committed to stable production, generating free cash flow and strengthening our balance sheet; our expected Q1/2020 production volumes and exploration and development expenditures; that we remain well positioned to generate free cash flow in 2020; 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.

In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: 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; 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, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2020 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, EBITDA, 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, EBITDA, 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 year ended December 31, 2019.

EBITDA is not a measurement based on GAAP in Canada. EBITDA is defined as net income or loss adjusted for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, payments on lease obligations, certain specific unrealized and non-cash transactions (including depletion, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation).

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

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be *included in our Annual Information Form for the year ended December 31, 2019, which will be filed on or before March 31, 2020. Listed below are cautionary statements that are specifically required by NI 51-101:*

- *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.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

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 year ended December 31, 2019. 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.

	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	14,334	14	45	14,503	16,810
Lloydminster	12,407	—	—	964	12,568
Canada - Light					
Viking	—	20,527	125	11,361	22,546
Duvernay	—	928	491	1,613	1,688
Remaining properties	—	889	703	20,528	5,013
United States					
Eagle Ford	—	21,229	8,865	53,773	39,055
Total	26,741	43,587	10,229	102,742	97,680

Capital efficiency means the cost to drill, complete, equip and tie-in a well divided by the initial production rate of the well on a boe basis over its initial 365 days of production.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Recycle ratio means operating netback divided by finding and development costs for the particular reserves category.

This press release discloses drilling inventory. Drilling inventory refers to Baytex's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Eagle Ford, Baytex's net drilling locations include 140 proved and 83 probable locations as at December 31, 2019 and 52 unbooked locations. In the Viking, Baytex's net drilling locations include 1,080 proved and 319 probable locations as at December 31, 2019 and 636 unbooked locations. In Peace River, Baytex's net drilling locations include 77 proved and 75 probable locations as at December 31, 2019 and 100 unbooked locations. In Lloydminster, Baytex's net drilling locations include 178 proved and 63 probable locations as at December 31, 2019 and 361 unbooked locations. In the Duvernay, Baytex's net drilling locations include 11 proved and 10 probable locations as at December 31, 2019 and 295 unbooked locations.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves".

Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

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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