BAYTEX
ENERGY CORP.

BAYTEX ANNOUNCES THIRD QUARTER 2019 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (November 1, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and nine months ended September 30, 2019 (all amounts are in Canadian dollars unless otherwise noted).

Strong operating performance has continued across our asset base during the third quarter. We continue to drive cost and capital efficiencies, stable production and substantial free cash flow. Given our year-to-date results, we expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d with exploration and development capital expenditures of approximately $560 million. 2019 exit production is forecast at 95,000-97,000 boe/d.

Our commitment remains to generate free cash flow and improve our balance sheet. We delivered free cash flow (adjusted funds flow less exploration and development capital expenditures) of $74 million in Q3/2019 and $271 million through the first nine months of 2019. This strong free cash flow has contributed to a 13% reduction in our net debt this year.

Q3/2019 Highlights

- Generated production of 94,927 boe/d (82% oil and NGL) in Q3/2019 and 98,125 boe/d (82% oil and NGL) for the first nine months of 2019.
- Delivered adjusted funds flow of $213 million ($0.38 per basic share) in Q3/2019 and $670 million ($1.20 per basic share) for the first nine months of 2019.
- Redeemed US$150 million principal amount of 6.75% senior unsecured notes at par on September 13, 2019.
- Reduced net debt by $57 million during the quarter ($294 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.
- Realized an operating netback (inclusive of hedging) of $28.66/boe.
- Eagle Ford production averaged 36,793 boe/d in Q3/2019 and 39,221 boe/d for the first nine months of 2019. We established average 30-day initial production rates of approximately 2,100 boe/d per well from 20 (4.6 net) wells that commenced production during the quarter, which represents an approximate 20% improvement over wells brought on-stream in 2018.
- Production in Canada averaged 58,134 boe/d in Q3/2019 and 58,904 boe/d for the first nine months of 2019. We successfully executed our third quarter development program in Canada with 102 (92.5 net) oil wells drilled.
- Using the forward strip for the remainder of 2019[1], we are forecasting adjusted funds flow for 2019 of approximately $875 million. Based on planned capital expenditures, we expect to generate approximately $300 million of free cash flow in 2019.

  (1) 2019 full-year pricing assumptions: WTI - US$56/bbl; LLS - US$62/bbl; WCS differential - US$12/bbl; MSW differential – US$5/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $1.54/mcf and Exchange Rate (CAD/USD) - 1.33.

- Published our fourth biennial corporate sustainability report, demonstrating our commitment to transparency and accountability, and our progress in managing the environmental and social impacts of our business. We established a greenhouse gas emissions reduction target with an objective of reducing our corporate emission intensity by 30% by 2021, relative to our 2018 baseline.

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	**September 30, 2019**	September 30, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 424,600**	$ 482,000	$ 436,761	**$ 1,360,024**	$ 1,070,433
Adjusted funds flow [1]	**213,379**	236,130	171,210	**670,279**	362,155
Per share - basic	**0.38**	0.42	0.46	**1.20**	1.28
Per share - diluted	**0.38**	0.42	0.45	**1.20**	1.28
Net income (loss)	**15,151**	78,826	27,412	**105,313**	(94,071)
Per share - basic	**0.03**	0.14	0.07	**0.19**	(0.33)
Per share - diluted	**0.03**	0.14	0.07	**0.19**	(0.33)
Capital Expenditures					
Exploration and development expenditures [1]	**$ 139,085**	$ 106,246	$ 139,195	**$ 399,174**	$ 311,559
Acquisitions, net of divestitures	**(30)**	1,647	—	**1,617**	(2,047)
Total oil and natural gas capital expenditures	**$ 139,055**	$ 107,893	$ 139,195	**$ 400,791**	$ 309,512
Net Debt					
Bank loan [2]	**$ 570,792**	$ 414,691	$ 490,565	**$ 570,792**	$ 490,565
Long-term notes [2]	**1,359,480**	1,543,645	1,527,733	**1,359,480**	1,527,733
Long-term debt	**1,930,272**	1,958,336	2,018,298	**1,930,272**	2,018,298
Working capital deficiency	**41,067**	70,350	93,792	**41,067**	93,792
Net debt [1]	**$ 1,971,339**	$ 2,028,686	$ 2,112,090	**$ 1,971,339**	$ 2,112,090
Shares Outstanding - basic (thousands)					
Weighted average	**557,888**	556,599	375,435	**556,651**	283,302
End of period	**557,972**	556,798	553,950	**557,972**	553,950
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 56.45**	$ 59.81	$ 69.50	**$ 57.06**	$ 66.75
LLS (US$/bbl)	**61.88**	67.15	75.25	**63.54**	71.24
LLS differential to WTI (US$/bbl)	**5.43**	7.34	5.75	**6.48**	4.49
Edmonton par ($/bbl)	**68.41**	73.84	81.92	**69.59**	78.19
Edmonton par differential to WTI (US$/bbl)	**(4.66)**	(4.61)	(6.82)	**(4.70)**	(6.03)
WCS heavy oil ($/bbl)	**58.39**	65.73	61.76	**60.24**	57.71
WCS differential to WTI (US$/bbl)	**(12.24)**	(10.68)	(22.25)	**(11.74)**	(21.93)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.23**	$ 2.64	$ 2.90	**$ 2.67**	$ 2.90
AECO ($/mcf)	**1.04**	1.17	1.35	**1.39**	1.41
CAD/USD average exchange rate	**1.3207**	1.3376	1.3070	**1.3292**	1.2877

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	**September 30, 2019**	September 30, 2018
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**42,829**	42,585	29,731	**43,479**	23,965
Heavy oil (bbl/d)	**25,712**	27,320	27,036	**26,637**	25,824
NGL (bbl/d)	**9,543**	10,986	10,076	**10,745**	9,549
Total liquids (bbl/d)	**78,084**	80,891	66,843	**80,861**	59,338
Natural gas (mcf/d)	**101,054**	105,065	93,414	**103,587**	89,449
Oil equivalent (boe/d @ 6:1) (3)	**94,927**	98,402	82,412	**98,125**	74,246
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 411,650**	$ 461,110	$ 417,213	**$ 1,309,396**	$ 1,015,356
Royalties	**(75,017)**	(86,617)	(91,945)	**(242,959)**	(233,989)
Operating expense	**(97,377)**	(100,474)	(77,698)	**(298,143)**	(213,735)
Transportation expense	**(9,903)**	(11,869)	(9,520)	**(35,102)**	(25,875)
Operating netback (1)	**$ 229,353**	$ 262,150	$ 238,050	**$ 733,192**	$ 541,757
General and administrative	**(9,934)**	(11,506)	(10,158)	**(35,576)**	(31,729)
Cash financing and interest	**(26,752)**	(28,092)	(26,343)	**(83,028)**	(76,384)
Realized financial derivatives gain (loss)	**20,857**	12,993	(30,854)	**52,664**	(70,103)
Other (5)	**(145)**	585	515	**3,027**	(1,386)
Adjusted funds flow (1)	**$ 213,379**	$ 236,130	$ 171,210	**$ 670,279**	$ 362,155
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 47.14**	$ 51.49	$ 55.03	**$ 48.88**	$ 50.09
Royalties	**(8.59)**	(9.67)	(12.13)	**(9.07)**	(11.54)
Operating expense	**(11.15)**	(11.22)	(10.25)	**(11.13)**	(10.54)
Transportation expense	**(1.13)**	(1.33)	(1.26)	**(1.31)**	(1.28)
Operating netback (1)	**$ 26.27**	$ 29.27	$ 31.39	**$ 27.37**	$ 26.73
General and administrative	**(1.14)**	(1.28)	(1.34)	**(1.33)**	(1.57)
Cash financing and interest	**(3.06)**	(3.14)	(3.47)	**(3.10)**	(3.77)
Realized financial derivatives gain (loss)	**2.39**	1.45	(4.07)	**1.97**	(3.46)
Other (5)	**(0.03)**	0.07	0.07	**0.11**	(0.06)
Adjusted funds flow (1)	**$ 24.43**	$ 26.37	$ 22.58	**$ 25.02**	$ 17.87

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 Q3/2019 MD&A for further information on these amounts.

Operating Results

Strong operating performance continued across our business during the third quarter. We continue to drive cost and capital efficiencies, stable production and substantial free cash flow.

Production during the third quarter averaged 94,927 boe/d (82% oil and NGL), as compared to 98,402 boe/d (82% oil and NGL) in Q2/2019. Our operating results were consistent with our expectations and reflect the timing of our 2019 development program in Canada and the Eagle Ford, and the impact of a third party facility turnaround at Peace River.

Production in the first nine months of 2019 averaged 98,125 boe/d. Given our strong performance year-to-date, we expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d with exploration and development expenditures of approximately $560 million. 2019 exit production is forecast at 95,000-97,000 boe/d.

Exploration and development expenditures totaled $139 million in Q3/2019, bringing aggregate spending in the nine months of 2019 to $399 million. We participated in the drilling of 124 (97.8 net) wells with a 100% success rate during the third quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 36,793 boe/d (77% liquids) during Q3/2019, as compared to 39,822 boe/d in Q2/2019. The lower volumes during the quarter reflect the timing of completion activity. We commenced production from 20 (4.6 net) wells during the third quarter, as compared to 29 (5.0 net) wells during the second quarter. The wells brought on-stream generated an average 30-day initial production rate of approximately 2,100 boe/d per well, which represents an approximate 20% improvement over wells brought on-stream in 2018.

During Q3/2019, production from the Viking averaged 22,198 boe/d, as compared to 22,565 boe/d in Q2/2019. We maintained an active pace of development during the third quarter with 72.5 net wells drilled and 49.4 net wells brought on production. We currently have three drilling rigs and two frac crews executing our program and expect to drill approximately 245 net wells this year. Inventory enhancement continues to be a priority. We have completed multiple deals and swaps year-to-date adding 220 net unbooked drilling opportunities.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 28,483 boe/d during the third quarter, as compared to 29,983 boe/d in Q2/2019. The lower volumes reflect the timing of our 2019 development program, which is strongly weighted (80%) to the second half of the year and the impact of a third party facility turnaround. During the third quarter, we drilled 20 net heavy oil wells, including four net multi-lateral horizontal wells at Peace River. Heavy oil production is expected to increase to more than 30,000 boe/d during the fourth quarter due to new well completions and the expansion of our Kerrobert thermal project.

East Duvernay Shale Light Oil

We continue to prudently advance the delineation of the East Duvernay Shale, an early stage, high operating netback light oil resource play. To-date, we have drilled seven wells at Pembina, which confirms 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% liquids) and are in the top 15% of all wells drilled to date in the play. 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 $213 million ($0.38 per basic share) in Q3/2019 and $670 million ($1.20 per basic share) through the first nine months of 2019. This resulted in free cash flow (adjusted funds flow less exploration and development capital expenditures) of $74 million in Q3/2019 and $271 million through the first nine months of 2019. This strong free cash flow has contributed to a 13% reduction in our net debt this year including the redemption of our US$150 million senior unsecured notes on September 13, 2019.

We realized an operating netback of $26.27/boe in Q3/2019, as compared to $29.27/boe in Q2/2019 and $31.39/boe in Q3/2018. Including financial derivatives, our operating netback improved to $28.66/boe, as compared to $27.32/boe in Q3/2018.

Our Canadian operations generated an operating netback of $25.43/boe during Q3/2019 while our Eagle Ford asset generated an operating netback of $27.58/boe. During the third quarter, Canadian differentials remained tight, which contributed to strong price realizations.

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

	Three Months Ended September 30					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**58,134**	**36,793**	**94,927**	45,214	37,198	82,412
Total sales, net of blending and other (1)	**$ 45.96**	**$ 48.99**	**$ 47.14**	$ 47.66	$ 63.98	$ 55.03
Royalties	**(4.90)**	**(14.42)**	**(8.59)**	(6.28)	(19.23)	(12.13)
Operating expense	**(13.78)**	**(6.99)**	**(11.15)**	(13.15)	(6.72)	(10.25)
Transportation expense	**(1.85)**	**—**	**(1.13)**	(2.29)	—	(1.26)
Operating netback (2)	**$ 25.43**	**$ 27.58**	**$ 26.27**	$ 25.94	$ 38.03	$ 31.39
Realized financial derivatives gain (loss)	**—**	**—**	**2.39**	—	—	(4.07)
Operating netback after financial derivatives	**$ 25.43**	**$ 27.58**	**$ 28.66**	$ 25.94	$ 38.03	$ 27.32

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.

Financial Liquidity

We are delivering on our commitment to generate meaningful free cash flow and improve our balance sheet. We redeemed US$150 million principal amount of 6.75% senior unsecured notes at par on September 13, 2019 with the redemption funded from free cash flow generated this year. During the third quarter, we reduced net debt by $57 million ($294 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar over this period. Our net debt, which includes our bank loan, long-term notes and working capital, totaled $1.97 billion at September 30, 2019.

We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021. Our credit facilities total approximately $1.06 billion, mature April 2021 and are comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices. In an effort to manage these exposures, 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 $21 million in Q3/2019 on these contracts.

For the fourth quarter of 2019, we have entered into hedges on approximately 53% of our net crude oil exposure. This includes 44% of our net WTI exposure with 20% fixed at US$62.35/bbl and 24% hedged utilizing a 3-way option structure that provides us with a US$10/bbl premium to WTI when WTI is at or below US$55.64/bbl and allows upside participation to US$73.65/bbl.

For 2020, we have entered into hedges on approximately 33% of our net crude oil exposure, largely utilizing a 3-way option structure that provides us with an US$8/bbl premium to WTI when WTI is at or below US$50.50/bbl and allows upside participation to US$63.59/bbl. In addition to the 3-way option structure, for the first quarter of 2020 we have also entered into WTI-based fixed price swaps for 4,000 bbl/d at US$55.90/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For Q4/2019, we expect to deliver 11,500 bbl/d (approximately 40%) of our heavy oil volumes to market by rail. For 2020, our crude by rail volumes are currently contracted at 7,500 bbl/d.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q3/2019 financial statements.

2019 Guidance

Given our strong year-to-date operating performance, we now expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d. 2019 exit production is forecast at 95,000-97,000 boe/d. We remain focused on driving cost and capital efficiencies in our business and anticipate exploration and development expenditures for 2019 of approximately $560 million.

Based on the forward strip for the balance of 2019[(1)], we are forecasting adjusted funds flow of approximately $875 million and expect to generate approximately $300 million of free cash flow, which supports our de-leveraging strategy. Adjusted funds flow in excess of exploration and development expenditures, leasing expenditures and asset retirement obligations, will be used to reduce our indebtedness.

(1) 2019 full-year pricing assumptions: WTI - US$56/bbl; LLS - US$62/bbl; WCS differential - US$12/bbl; MSW differential – US$5/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $1.54/mcf and Exchange Rate (CAD/USD) - 1.33.

As we continue to drive debt levels down, we will be positioned to enhance shareholder returns through a combination of organic growth, disciplined capital allocation, share buybacks and/or reinstatement of a dividend.

The following table summarizes our 2019 annual guidance and compares it to our 2019 year-to-date actual results.

	Previous Guidance [(1)]	Current Guidance	YTD 2019
Exploration and development capital ($ millions)	$550 - $600	~ $560	$399.2
Production (boe/d)	96,000 - 97,000	~ 97,000	98,125
Expenses:			
Royalty rate (%)	19 %	No change	19 %
Operating ($/boe)	$10.75 - $11.25	No change	$11.13
Transportation ($/boe)	$1.25 - $1.35	No change	$1.31
General and administrative ($ millions)	$46 ($1.30/boe)	No change	$35.6 ($1.33/boe)
Interest ($ millions)	$112 ($3.23/boe)	No change	$83.0 ($3.10/boe)
Leasing expenditures ($ millions)	$5	No change	4.4
Asset retirement obligations ($ millions)	$17	No change	10.9

(1) As announced on August 1, 2019.

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

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

Baytex will host a conference call today, November 1, 2019, 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/baytexq320191101.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 condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 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; our 2019 production, exit production and capital expenditure guidance; that we are committed to generate free cash flow and improve our balance sheet; our forecast for 2019 adjusted funds flow and free cash flow; our GHG emissions intensity reduction target; in the Viking: that we expect to drill 245 wells in 2019 and inventory enhancement is a priority; that heavy oil production will increase to 30,000 boe/d in Q4/2019; in the East Duvernay shale: that we continue to prudently advance the delineation of the asset and that we have de-risked our 38 kilometer acreage fairway; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our net crude oil and natural gas exposure that is hedged for 2019 and 2020 and the amount and percentage of heavy oil production we expect to delivery by crude by rail and the percentage of crude by rail deliveries that do not have WCS exposure; that we expect to exceed our 2019 full-year production guidance; our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net debt to adjusted funds flow ratio; that we will be positioned to enhance shareholder returns through organic growth, capital allocation, the reinstatement of a dividend and/or share buybacks; guidance for 2019 capital spending and production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligation expenditures; and that we expect to release our 2020 budget in December 2019. In addition, information and statements relating to reserves and contingent resources 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.

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, 2018, 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

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, 2019.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less sustaining capital. Sustaining capital is an estimate of the amount of exploration and development expenditures required to offset production declines on an annual basis and maintain flat production volumes.

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. 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.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the bank loan. 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

This press release discloses the acquisition of 220 net unbooked drilling opportunities in our Viking asset. The additional drilling opportunities are unbooked locations and 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.

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.

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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