BAYTEX ANNOUNCES FIRST QUARTER 2019 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (May 2, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months ended March 31, 2019 (all amounts are in Canadian dollars unless otherwise noted).

“This marks the first quarter where we have demonstrated the benefit of the Baytex and Raging River combination as we have increased our operating netback, delivered meaningful free cash flow and started to strengthen our balance sheet. Our first quarter results were underpinned by robust operating performance across our asset base in Canada and the U.S. Our sound operating results, combined with improved pricing in Canada, resulted in a 100% increase in our adjusted funds flow compared to the fourth quarter of 2018. We are well positioned to execute our business plan focused on free cash flow generation,” commented Ed LaFehr, President and Chief Executive Officer.

2019 Outlook

Based on the forward strip for 2019(1), we are now forecasting adjusted funds flow for 2019 of approximately $950 million. Further deleveraging remains a top priority with adjusted funds flow now exceeding the midpoint of our capital guidance by $350 million, which will support accelerated debt repayment.

Given our strong operating performance to date, we are tightening our 2019 production guidance range to 95,000 to 97,000 boe/d (previously 93,000 to 97,000 boe/d) with budgeted exploration and development capital expenditures of $575 to $625 million (previously $550 to $650 million).

(1) Pricing assumptions: WTI - US$61/bbl; LLS - US$67/bbl; WCS differential - US$15/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.80/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.34.

Q1/2019 Highlights

- Generated production of 101,115 boe/d (84% oil and NGL), exceeding the high end of our annual guidance and a 2% increase over Q4/2018.
- Delivered adjusted funds flow of $221 million ($0.40 per basic share), a 100% increase compared to $111 million ($0.20 per basic share) in Q4/2018.
- Reduced net debt by $90 million during the quarter as adjusted funds flow exceeded capital expenditures.
- Realized an operating netback of $26.56/boe ($28.63/boe including financial derivatives).
- Eagle Ford production increased 7% to 41,097 boe/d, representing the highest quarterly production rate achieved in the field and reflects continued strong well performance and an active first quarter completion program.
- Production in Canada remained strong at 60,018 boe/d. We maintained a consistent development program in the Viking and reinitiated activity on our heavy oil assets, including the completion of three previously deferred wells at Peace River.
- Continued to advance the evaluation of the East Duvernay Shale where two of four planned wells were drilled. Completion activities are scheduled to commence in Q2/2019 to confirm well productivities and the de-risking of the majority of our 250 sections of land in the Pembina area.
- Extended the maturity of our revolving credit facilities to April 2021. We maintain strong financial liquidity with our credit facilities approximately 50% undrawn.

		Three Months Ended	
	March 31, 2019	December 31, 2018	March 31, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 453,424**	$ 358,437	$ 286,067
Adjusted funds flow (1)	**220,770**	110,828	84,255
Per share - basic	**0.40**	0.20	0.36
Per share - diluted	**0.40**	0.20	0.36
Net income (loss)	**11,336**	(231,238)	(62,722)
Per share - basic	**0.02**	(0.42)	(0.27)
Per share - diluted	**0.02**	(0.42)	(0.27)
Capital Expenditures			
Exploration and development expenditures (1)	**$ 153,843**	$ 184,162	$ 93,534
Acquisitions, net of divestitures	**-**	183	(2,026)
Total oil and natural gas capital expenditures	**$ 153,843**	$ 184,345	$ 91,508
Net Debt			
Bank loan (2)	**$ 550,751**	$ 522,294	$ 212,571
Long-term notes (2)	**1,569,153**	1,596,323	1,525,595
Long-term debt	**2,119,904**	2,118,617	1,738,166
Working capital deficiency	**55,337**	146,550	45,213
Net debt (1)	**$ 2,175,241**	$ 2,265,167	$ 1,783,379
Shares Outstanding - basic (thousands)			
Weighted average	**555,438**	554,036	236,315
End of period	**555,872**	554,060	236,578

	Three Months Ended		
	March 31, 2019	December 31, 2018	March 31, 2018
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**45,048**	44,987	20,967
Heavy oil (bbl/d)	**26,891**	26,339	24,868
NGL (bbl/d)	**11,729**	10,327	9,143
Total liquids (bbl/d)	**83,668**	81,653	54,978
Natural gas (mcf/d)	**104,682**	103,424	87,261
Oil equivalent (boe/d @ 6:1) (3)	**101,115**	98,890	69,522
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (4)	**$ 436,636**	$ 344,682	$ 268,777
Royalties	**(81,325)**	(79,765)	(64,839)
Operating expense	**(100,292)**	(97,857)	(65,888)
Transportation expense	**(13,330)**	(10,994)	(8,519)
Operating netback	**$ 241,689**	$ 156,066	$ 129,531
General and administrative	**(14,136)**	(14,096)	(11,008)
Cash financing and interest	**(28,184)**	(27,933)	(24,511)
Realized financial derivatives gain (loss)	**18,814**	(3,063)	(9,841)
Other (5)	**2,587**	(146)	84
Adjusted funds flow (1)	**$ 220,770**	$ 110,828	$ 84,255
Netback (per boe)			
Total sales, net of blending and other expense (4)	**$ 47.98**	$ 37.89	$ 42.96
Royalties	**(8.94)**	(8.77)	(10.36)
Operating expense	**(11.02)**	(10.76)	(10.53)
Transportation expense	**(1.46)**	(1.21)	(1.36)
Operating netback (1)	**$ 26.56**	$ 17.15	$ 20.71
General and administrative	**(1.55)**	(1.55)	(1.76)
Cash financing and interest	**(3.10)**	(3.07)	(3.92)
Realized financial derivatives gain (loss)	**2.07**	(0.34)	(1.57)
Other (5)	**0.28**	(0.02)	0.01
Adjusted funds flow (1)	**$ 24.26**	$ 12.17	$ 13.47

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. We refer you to 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 liquidity 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 Q1/2019 MD&A for further information on these amounts.

Operating Results

Our operating results for the first quarter of 2019 were buoyed by record production in the Eagle Ford and strong operating performance in Canada in a much improved commodity price environment. We successfully executed our first quarter drilling program and continued to drive cost and capital efficiency in our business. We are now realizing the benefits of the Baytex and Raging River combination as we increase our operating netback, deliver meaningful free cash flow and strengthen our balance sheet.

Production during the first quarter averaged 101,115 boe/d (84% oil and NGL), as compared to 98,890 boe/d (83% oil and NGL) in Q4/2018, exceeding the high end of our full-year production guidance range.

Exploration and development expenditures totaled $154 million in Q1/2019, consistent with the mid-point of our guidance range of $600 million. We participated in the drilling of 126 (86.6 net) wells with a 99% success rate during the first quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 41,097 boe/d (78% liquids) during Q1/2019, as compared to 38,437 boe/d in Q4/2018. This represents the highest quarterly production rate ever achieved in the field and reflects continued strong well performance and an active first quarter completion program. We commenced production from 36 (8.9 net) wells during the first quarter, representing approximately one-third of our planned 2019 activity. The wells brought on-stream generated an average 30-day initial production rate of approximately 1,600 boe/d per well.

During Q1/2019, production from the Viking averaged 23,387 boe/d, as compared to 23,784 boe/d in Q4/2018. We maintained a steady pace of development in Q1/2019 with five drilling rigs and 1.5 frac crews executing our program, resulting in 79 (67.8 net) wells. We continue to experience positive results from our extended reach horizontal drilling program, which now represents 85% of our Viking activity. Our capital program includes the seasonal slowdown in Q2/2019 and we remain on track to drill approximately 250 net wells this year.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 29,341 boe/d during the first quarter, as compared to 28,290 boe/d in Q4/2018. As commodity prices and operating netbacks improved during the first quarter, we reinitiated field activity, including the completion of three previously deferred wells at Peace River. In addition, we continued the ramp-up of our Kerrobert thermal expansion project achieving a peak production rate of 2,500 bbl/d. We have also expanded our acreage position at Peace River, acquiring an additional 26 sections of prospective land. We expect to drill our first exploratory multilateral well on these lands in 2019.

With WCS differentials returning to historical levels, the returns associated with continued development of our heavy oil assets are now competitive or superior to those of our other plays, allowing potential increased capital allocation to those assets in the second half of 2019.

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 where we have amassed over 450 sections of land. During Q1/2019, we drilled two of four planned land retention and appraisal wells. The wells drilled to date have confirmed that the net reservoir thickness and geological characteristics remain consistent through the southern extent of our Pembina acreage. Completion activities are scheduled to commence in Q2/2019 to confirm well productivities and the de-risking of the majority of our 250 sections of land in the Pembina area.

Financial Review

Our adjusted funds flow in Q1/2019 increased 100% as compared to Q4/2018, driven by strong operating performance and the cash generating capability of our assets in an improved commodity price environment. We generated adjusted funds flow of $221 million ($0.40 per basic share) in Q1/2019, compared to $111 million ($0.20 per basic share) in Q4/2018.

In Q1/2019, the price for West Texas Intermediate light oil (“WTI”) averaged US$54.90/bbl, as compared to US$58.81/bbl in Q4/2018. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select (“WCS”) and WTI, averaged US$12.29/bbl in Q1/2019 as compared to US$39.42/bbl in Q4/2018. The discount for Canadian light oil, as measured by the price differential between Canadian Mixed Sweet Blend ("MSW") and WTI, averaged US$4.85/bbl in Q1/2019 as compared to US$26.51/bbl in Q4/2018.

We generated an operating netback of $26.56/boe in Q1/2019, as compared to $17.15/boe in Q4/2018 and $20.71/boe in Q1/2018. The Eagle Ford generated an operating netback of $28.94/boe during Q1/2019 while our Canadian operations generated an operating netback of $24.92/boe.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the LLS crude oil benchmark, which is a function of the Brent price. In Q1/2019, the price for LLS averaged US$61.60/bbl as compared to US$66.64/bbl in Q4/2018. During Q1/2019, our light oil and condensate realized price in the Eagle Ford was US$57.23/bbl (or $76.06/bbl) representing a US$4.37/bbl discount to LLS.

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

	Three Months Ended March 31					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**60,018**	**41,097**	**101,115**	33,505	36,017	69,522
Total sales, net of blending and other [(1)]	**$ 45.77**	**$ 51.20**	**$ 47.98**	$ 29.69	$ 55.30	$ 42.96
Royalties	**(4.66)**	**(15.18)**	**(8.94)**	(3.76)	(16.51)	(10.36)
Operating expense	**(13.72)**	**(7.08)**	**(11.02)**	(15.06)	(6.31)	(10.53)
Transportation expense	**(2.47)**	**—**	**(1.46)**	(2.83)	—	(1.36)
Operating netback [(2)]	**$ 24.92**	**$ 28.94**	**$ 26.56**	$ 8.04	$ 32.48	$ 20.71
Realized financial derivatives gain (loss)	**—**	**—**	**2.07**	—	—	(1.57)
Operating netback after financial derivatives	**$ 24.92**	**$ 28.94**	**$ 28.63**	$ 8.04	$ 32.48	$ 19.14

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. We refer you to the advisory on non-GAAP measures at the end of this press release.

Financial Liquidity

On May 2, 2019, we extended the maturity of our revolving credit facilities to April 2021. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. Our credit facilities total approximately $1.07 billion, comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.2 billion at March 31, 2019, down from $2.3 billion at December 31, 2018. We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021.

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, crude-by-rail and capital allocation optimization to reduce the volatility in our adjusted funds flow. We realized a financial derivatives gain of $19 million in Q1/2019.

For the balance of 2019, we have now entered into hedges on approximately 45% of our net crude oil exposure, up from approximately 30% two months ago. This includes 40% of our net WTI exposure with 17% fixed at US$62.72/bbl and 23% 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. In addition, we have entered into a Brent-based 3-way option structure for 3,000 bbl/d that provides a US$10/bbl premium to Brent when Brent is at or below US$59.50/bbl and allows upside participation to US$78.68/bbl. We have also entered into hedges on approximately 22% of our net natural gas exposure through a series of NYMEX swaps at US$3.10/mmbtu. For 2020, we have entered into hedges on approximately 15% of our net crude oil exposure, utilizing a 3-way option structure that provides us with a US$9/bbl premium to WTI when WTI is at or below US$51.00/bbl and allows upside participation to US$66.06/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2019, we expect to deliver 11,000 bbl/d (approximately 40%) of our heavy oil volumes to market by rail, up from 9,000 bbl/d in 2018. Approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure. In addition, for the balance of 2019, we have entered into WCS differential hedges on approximately 13% of our net heavy oil exposure at a WTI-WCS differential of US$17.49/bbl. We have also entered into a WTI-MSW basis differential swap for 4,000 bbl/d of our light oil production in Canada at US$8/bbl for June 2019 to December 2019.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q1/2019 financial statements.

Outlook for 2019

Global benchmark prices have continued to improve with WTI currently trading at US$64/bbl, as compared to an average of US$55/bbl in Q1/2019. In addition, Canadian light and heavy oil differentials remain strong. For April and May, the WTI-WCS price differential averaged US$10.62/bbl and US$8.43/bbl, respectively, and the WTI-MSW price differential averaged US$4.69/bbl and US$3.70/bbl, respectively. This combination of improved WTI prices and the narrowing of Canadian differentials is expected to have a further positive impact to our full year adjusted funds flow.

Given our strong Q1/2019 operating performance, we are tightening our 2019 production guidance range to 95,000 to 97,000 boe/d (previously 93,000 to 97,000 boe/d) with budgeted exploration and development capital expenditures of $575 to $625 million (previously $550 to $650 million). We are also updating our guidance for general and administrative expense to reflect a change associated with the adoption of IFRS 16.

Based on the forward strip for 2019[1], we are forecasting adjusted funds flow of approximately $950 million. Further deleveraging remains a top priority. For 2019, adjusted funds flow in excess of exploration and development expenditures, leasing expenditures and asset retirement obligations, will be used to reduce our indebtedness. Our year end 2019 net debt to adjusted funds flow ratio is forecast to be 2.0x.

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, the reinstatement of a dividend and/or share buybacks.

The following table summarizes our updated 2019 annual guidance.

	Guidance	Q1/2019
Exploration and development capital ($ millions) [2]	$575 - $625	$153.8
Production (boe/d) [2]	95,000 - 97,000	101,115
Expenses:		
Royalty rate (%)	20%	18.6%
Operating ($/boe)	$10.75 - $11.25	$11.02
Transportation ($/boe)	$1.25 - $1.35	$1.46
General and administrative ($ millions)	$46 ($1.30/boe)	$14.1 ($1.55/boe)
Interest ($ millions)	$112 ($3.23/boe)	$28.2 ($3.10/boe)
Leasing expenditures ($ millions)	$5	1.4
Asset retirement obligations ($ millions)	$17	4.9

(1) Pricing assumptions: WTI - US$61/bbl; LLS - US$67/bbl; WCS differential - US$15/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.80/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.34.

(2) Our exploration and development capital and production guidance for 2019 has been updated as of May 2, 2019. Original guidance from December 2018: production – 93,000-97,000 boe/d; exploration and development capital - $550-$650 million.

The following table summarizes our annual adjusted funds flow sensitivities to changes in commodity prices and the CAD/USD exchange rate.

	Excluding Hedges ($ millions)	**Including Hedges ($ millions)**
Change of US$1.00/bbl WTI crude oil	$29.1	$21.3
Change of US$1.00/bbl WCS heavy oil differential	$11.3	$9.3
Change of US$1.00/bbl MSW light oil differential	$10.6	$10.6
Change of US$0.25/mcf NYMEX natural gas	$9.2	$7.3
Change of $0.01 in the CAD/USD exchange rate	$12.2	$12.2

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 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.

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

Baytex will host a conference call tomorrow, May 3, 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/baytexq120190503.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 "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 are focused on free cash flow generation; our forecast for adjusted funds flow and debt repayment; that deleveraging is a top priority; our 2019 production and capital expenditure guidance; that we expect to drill 250 wells in the Viking play in 2019; that we expect to drill an exploratory well on new lands in Peace River in 2019; that WCS differentials mean that our heavy oil assets are competitive or superior to our other assets and could be allocated more capital in H2/2019; that we continue to prudently advance the delineation of our East Duvernay Shale assets and the timing and impact of our planned completion activities in the East Duvernay; 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; the expected impact of improved pricing on our adjusted funds flow; that deleveraging remains a priority and our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net dent 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 our 2019 production, capital expenditure guidance, adjusted funds flow, adjusted funds flow per share and operating netback guidance; our expected royalty rate and operating, transportation, general and administration and interest expenses for 2019; our expected leasing expenditures and asset retirement obligation spending for 2019; the sensitivity of our 2019 Adjusted Funds Flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/US$ exchange rate. 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 months ended March 31, 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 liquidity 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.

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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