BAYTEX
ENERGY CORP.

BAYTEX REPORTS Q3 2017 RESULTS AND BOARD APPOINTMENT

CALGARY, ALBERTA (November 2, 2017) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and nine months ended September 30, 2017 (all amounts are in Canadian dollars unless otherwise noted).

“We continue to reposition our business for the current low commodity price environment by reducing our cash costs and improving capital efficiencies. I am pleased that production is trending toward the high end of guidance while our capital program is funded within cash flow. In the Eagle Ford, strong well performance mitigated the impact of Hurricane Harvey. In Canada, our drilling program continues to deliver solid results and we have achieved substantial cost reductions on our acquired assets at Peace River. We maintain strong financial liquidity and our first long-term note maturity is not until 2021,” commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Produced 69,310 boe/d (80% oil and NGL) in Q3/2017 and 70,473 boe/d (79% oil and NGL) for the first nine months of 2017;
- Delivered funds from operations ("FFO") of $77.3 million ($0.33 per basic share) in Q3/2017 and $241.8 million ($1.03 per basic share) in the first nine months of 2017;
- Established average 30-day initial gross production rates of approximately 1,500 boe/d per well from 22 gross (5.8 net) wells in the Eagle Ford that commenced production in the third quarter;
- Reduced net debt by $70.6 million in Q3/2017 through excess FFO, a non-core asset sale and the strengthening of the Canadian dollar relative to the U.S. dollar;
- Achieved a 35% reduction in operating expenses on our recently acquired Peace River lands, which contributed to a further 5% reduction in annual guidance to $10.50/boe; and
- Tightened 2017 production guidance range to 69,500 to 70,000 boe/d (previously 69,000 to 70,000 boe/d) despite the impact of Hurricane Harvey in the third quarter.

	Three Months Ended			**Nine Months Ended**	
	September 30, 2017	June 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 254,430**	$ 274,369	$ 197,648	**$ 789,348**	$ 546,979
Funds from operations (1)	**77,340**	83,136	72,106	**241,845**	199,012
Per share - basic	**0.33**	0.35	0.34	**1.03**	0.94
Per share - diluted	**0.33**	0.35	0.34	**1.02**	0.94
Net income (loss)	**(9,228)**	9,268	(39,430)	**11,136**	(125,760)
Per share - basic	**(0.04)**	0.04	(0.19)	**0.05**	(0.60)
Per share - diluted	**(0.04)**	0.04	(0.19)	**0.05**	(0.60)
Exploration and development	**61,544**	78,007	39,579	**236,110**	156,754
Acquisitions, net of divestitures	**(7,436)**	5,226	(62,752)	**63,794**	(62,798)
Total oil and natural gas capital expenditures	**$ 54,108**	$ 83,233	$ (23,173)	**$ 299,904**	$ 93,956
Bank loan (2)	**$ 226,249**	$ 264,032	$ 289,859	**$ 226,249**	$ 289,859
Long-term notes (2)	**1,488,450**	1,541,694	1,544,510	**1,488,450**	1,554,510
Long-term debt	**1,714,699**	1,805,726	1,844,369	**1,714,699**	1,844,369
Working capital deficiency	**34,106**	13,661	19,653	**34,106**	19,653
Net debt (3)	**$ 1,748,805**	$ 1,819,387	$ 1,864,022	**$ 1,748,805**	$ 1,864,022

	Three Months Ended			Nine Months Ended	
	September 30, 2017	June 30, 2017	September 30, 2016	**September 30, 2017**	September 30, 2016
OPERATING					
Daily production					
Heavy oil (bbl/d)	**26,161**	25,577	24,132	**25,454**	23,789
Light oil and condensate (bbl/d)	**20,041**	22,370	19,001	**21,343**	21,785
NGL (bbl/d)	**8,940**	9,693	9,149	**8,982**	9,695
Total oil and NGL (bbl/d)	**55,142**	57,640	52,282	**55,779**	55,269
Natural gas (mcf/d)	**85,006**	91,028	89,314	**88,166**	94,253
Oil equivalent (boe/d @ 6:1) (4)	**69,310**	72,812	67,167	**70,473**	70,978
Benchmark prices					
WTI oil (US$/bbl)	**48.20**	48.29	44.94	**49.46**	41.34
WCS heavy oil (US$/bbl)	**38.26**	37.16	31.44	**37.59**	27.66
Edmonton par oil ($/bbl)	**56.74**	61.92	54.80	**60.87**	50.14
LLS oil (US$/bbl)	**50.27**	49.70	45.82	**50.82**	41.76
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**38.18**	37.62	29.79	**37.29**	23.91
Light oil and condensate ($/bbl)	**58.22**	60.68	53.25	**60.75**	47.27
NGL ($/bbl)	**25.18**	22.70	14.96	**24.65**	15.58
Total oil and NGL ($/bbl)	**43.36**	44.06	35.72	**44.23**	31.65
Natural gas ($/mcf)	**2.89**	3.62	2.95	**3.35**	2.42
Oil equivalent ($/boe)	**38.04**	39.41	31.73	**39.20**	27.86
CAD/USD noon rate at period end	**1.2510**	1.2983	1.3117	**1.2510**	1.3117
CAD/USD average rate for period	**1.2524**	1.3447	1.3051	**1.3067**	1.3228
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**4.13**	4.81	7.72	**6.97**	9.04
Low	**2.76**	2.87	4.76	**2.76**	1.57
Close	**3.76**	3.15	5.57	**3.76**	5.57
Volume traded (thousands)	**156,562**	216,383	377,435	**628,577**	1,326,946
NYSE					
Share price (US$)					
High	**3.16**	3.63	6.18	**5.20**	7.14
Low	**2.13**	2.15	3.59	**2.13**	1.08
Close	**3.01**	2.43	4.25	**3.01**	4.25
Volume traded (thousands)	**81,848**	109,758	168,984	**330,759**	521,550
Common shares outstanding (thousands)	**235,451**	234,204	211,542	**235,451**	211,542

Notes:

(1) *Funds from operations 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 funds from operations as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement expenditures. Baytex's determination of funds from operations may not be comparable to other issuers. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends. For a reconciliation of funds from operations 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, 2017.*

(2) *Principal amount of instruments.*

(3) *Net debt is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities excluding current financial derivatives and onerous contracts) and the principal amount of both the long-term notes and the bank loan.*

(4) *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.*

(5) *Heavy oil prices are calculated based on sales volumes, net of blending costs.*

Operating Results

Our operating results for the third quarter reflect strong performance across our three core operating areas as we position our business for success in a lower commodity price environment. In the Eagle Ford, enhanced completions continue to drive strong well performance. In Peace River, we drilled our first well on the recently acquired acreage with results exceeding our budget expectation. In Lloydminster, our drilling program continues to generate impressive results.

Production averaged 69,310 boe/d (80% oil and NGL) in Q3/2017, as compared to 72,812 boe/d (79% oil and NGL) in Q2/2017. Production in the first nine months of 2017 averaged 70,473 boe/d. During the third quarter, exploration and development capital expenditures totaled $61.5 million and we participated in the drilling of 50 (15.3 net) wells with a 100% success rate.

We employ a flexible approach to prudently manage our capital program as we target exploration and development capital expenditures at a level that approximates our FFO. In the first nine months of 2017, exploration and development capital expenditures totaled $236.1 million, as compared to FFO of $241.8 million.

As previously disclosed, due to Hurricane Harvey, on August 25, 2017 our Eagle Ford operations were shut-in and drilling and completion operations were suspended. With very little damage to production facilities on Baytex lands, production in the Eagle Ford steadily increased as market access improved and production was restored to pre-hurricane levels by mid-September. Due to flush production from well restarts in September, we estimate downtime in the third quarter of approximately 1,500 boe/d, as compared to our prior estimate of 2,500 boe/d.

We continuously evaluate opportunities to optimize and enhance our portfolio. During the third quarter, we disposed of our Red Earth assets located in north central Alberta for net proceeds of $7.3 million. The assets were producing approximately 250 boe/d of crude oil at the time of closing and included undiscounted asset retirement obligations of $11.6 million.

Due to low natural gas prices in Alberta and our desire to optimize the value of our resource base, we shut-in approximately 6 mmcf/d (approximately 1,000 boe/d) of natural gas production during the month of October. We subsequently re-started this production as natural gas prices improved.

We are tightening our 2017 production guidance to 69,500 to 70,000 boe/d (previously 69,000 to 70,000 boe/d), despite the impact of Hurricane Harvey in the Eagle Ford and the shut-in of natural gas production in Alberta. We are maintaining our capital budget guidance at $310 to $330 million. We continue to drive cost efficiencies in our business with notable operating expense savings in Peace River. Following a 4% reduction in our annual guidance for operating expenses in the second quarter, we are reducing our guidance a further 5% to $10.50/boe.

We are in the process of setting our 2018 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The assets generate the highest cash netbacks in our portfolio and contain a significant inventory of development prospects. In Q3/2017, we directed 76% of our exploration and development expenditures toward these assets.

Production during the third quarter averaged 34,750 boe/d (77% liquids), as compared to 38,528 boe/d in Q2/2017. The reduced volumes reflect the impact of Hurricane Harvey combined with fewer net wells brought on production in Q3/2017 relative to the first half of 2017.

During the third quarter, we averaged 3-4 drilling rigs and 1-2 completion crews on our lands. In Q3/2017, we participated in the drilling of 30 (7.9 net) wells and commenced production from 22 (5.8 net) wells. At quarter end, we had 48 (13.8 net) wells waiting on completion.

We continue to see strong well performance driven by enhanced completions in Karnes County. In addition, early results from Atascosa County are encouraging as we exploit the oil window on the western portion of our lands. The wells that commenced production during the quarter established 30-day initial gross production rates of approximately 1,500 boe/d per well. During the third quarter, we averaged 28 effective frac stages per well and proppant per completed foot of approximately 1,800 pounds.

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry. In addition, through detailed re-mapping of the Bluesky formation, we have been able to effectively increase our exposure to pay in the laterals of new wells, achieving 97% in zone performance.

Production was stable during the third quarter, averaging 18,400 boe/d (93% heavy oil), as compared to 18,300 boe/d in Q2/2017. We drilled 1 (1.0 net) well during the third quarter and 8 (8.0 net) wells during the first nine months of 2017. These wells have established an average 30-day initial production rate of approximately 400 bbl/d per well.

Our Peace River team has been working diligently to integrate our recent acquisition in Peace River as we align the acquired assets with our operating philosophy. During the third quarter, we drilled our first well at Seal, which generated a 30-day initial production rate of approximately 400 bbl/d. We also restarted 10 pads that were shut-in at the time of the acquisition, resulting in incremental production of 800 bbl/d. We have undertaken an extensive review of operations to ensure regulatory compliance and have made meaningful progress in reducing operating costs. To-date, we have achieved a 35% reduction with further improvements anticipated in 2018 and beyond. Production on the acquired assets averaged 3,800 boe/d during the third quarter, up 26% from the time of the acquisition.

Lloydminster

Our Lloydminster region, which straddles the Alberta and Saskatchewan border, is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical and horizontal drilling, water flood and steam-assisted gravity drainage operations. We have also adopted, where applicable, the multi-lateral well design and geosteering capability that we have successfully utilized at Peace River.

Production averaged approximately 9,100 boe/d (98% heavy oil) during the third quarter, as compared to 8,600 boe/d in Q2/2017. The higher volumes reflect an increased pace of development activity following spring break-up. We drilled 19 (6.4 net) wells during the third quarter and 41 (21.3 net) wells during the first nine months of 2017. During the third quarter, three operated wells (including two multi-lateral horizontal wells) established an average 30-day initial production rate of approximately 200 bbl/d per well.

Financial Review

We generated FFO of $77.3 million ($0.33 per share) in Q3/2017, compared to $83.1 million ($0.35 per share) in Q2/2017. The decrease in FFO is largely due to lower production volumes associated with Hurricane Harvey and the decline in crude oil prices, expressed in Canadian dollars, due to the strengthening of the Canadian dollar relative to the U.S. dollar.

In the first nine months of 2017, we generated FFO of $241.8 million ($1.03 per share), compared to $199.0 million ($0.94 per share) in the first nine months of 2016. This increase is largely attributable to higher realized commodity prices.

Financial Liquidity

We continue to maintain strong financial liquidity as our US$575 million revolving credit facilities are approximately two-thirds undrawn and our first long-term note maturity is not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our funds from operations, we expect this liquidity position to be stable going forward.

Our revolving credit facilities, which currently mature in June 2019, are covenant-based and do not require annual or semi-annual reviews. We are well within our financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at September 30, 2017 was 0.6:1.0, compared to a maximum permitted ratio of 5.0:1.0, and our interest coverage ratio was 4.2:1.0, compared to a minimum required ratio of 1.25:1.0.

Our net debt totaled $1.75 billion at September 30, 2017, which is down $115 million from September 30, 2016. Our net debt is comprised of over 75% U.S. dollar borrowings and with the recent strengthening of the Canadian dollar relative to the U.S. dollar, our net debt expressed in Canadian dollars is reduced. Additionally, our exposure to fluctuations in the Canada-U.S. dollar exchange rate is mitigated as more than half of our operations are in the U.S. and approximately 70% of our 2017 exploration and development capital program is forecast to be invested in the U.S.

Operating Netback

In Q3/2017, the price for West Texas Intermediate light oil ("WTI") averaged US$48.20/bbl, as compared to US$48.29/bbl in Q2/2017. While WTI was relatively stable during the third quarter, we benefited from an improved pricing environment for Canadian heavy oil. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$9.94/bbl, as compared to US$11.13/bbl in Q2/2017.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the Louisiana Light Sweet ("LLS") crude oil benchmark, which is a function of the Brent price. As a result, we are currently benefiting from a widening of the Brent-WTI spread. In addition, increased competition for physical field supplies has resulted in improved price realizations relative to LLS. During the third quarter, our light oil and condensate price in the Eagle Ford of US$45.78/bbl (or $58.59/bbl) represented a US$3.49/bbl discount to LLS, as compared to a historical discount of approximately US$6.00/bbl.

We generated an operating netback in Q3/2017 of $17.83/boe ($18.27/boe including financial derivatives gain), as compared to $18.30/boe ($18.70/boe including financial derivatives gain) in Q2/2017 and $13.91/boe ($16.95/boe including financial derivatives gain) in Q3/2016. The Eagle Ford generated an operating netback of $23.53/boe during Q3/2017 while our Canadian operations generated an operating netback of $12.08/boe.

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

	Three Months Ended September 30					
	2017			2016		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**34,560**	**34,750**	**69,310**	33,615	33,552	67,167
Realized sales price	**$ 33.41**	**$ 42.64**	**$ 38.04**	$ 26.52	$ 36.95	$ 31.73
Less:						
Royalty	**4.71**	**12.58**	**8.65**	3.85	10.89	7.37
Operating expense	**13.69**	**6.53**	**10.10**	12.32	5.82	9.07
Transportation expense	**2.93**	**—**	**1.46**	2.76	—	1.38
Operating netback	**$ 12.08**	**$ 23.53**	**$ 17.83**	$ 7.59	$ 20.24	$ 13.91
Realized financial derivatives gain	**—**	**—**	**0.44**	—	—	3.04
Operating netback after financial derivatives gain	**$ 12.08**	**$ 23.53**	**$ 18.27**	$ 7.59	$ 20.24	$ 16.95

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our FFO. We realized a financial derivatives gain of $2.8 million in Q3/2017.

For the fourth quarter of 2017, we have entered into hedges on approximately 48% of our net WTI exposure with 9% fixed at US$54.46/bbl and 39% hedged utilizing a 3-way option structure that provides us with downside price protection at US$47.17/bbl and upside participation to US$58.60/bbl. We have also entered into hedges on approximately 48% of our net WCS differential exposure at a price differential to WTI of US$13.67/bbl and 62% of our net natural gas exposure through a combination of AECO swaps at C$3.00/mcf and NYMEX swaps at US$2.98/mmbtu.

We are also executing our hedge program for 2018. We have now entered into hedges on approximately 23% of our net WTI exposure with 18% fixed at US$51.18/bbl and 5% hedged utilizing a 3-way option structure that provides us with downside price protection at US$54.40/bbl and upside participation to US$60.00/bbl. To enhance the value of our fixed price hedges, we have entered into WTI swaptions at an average price of US$51.28/bbl, which, if exercised on December 29, 2017, would bring our crude oil hedge position for 2018 to approximately 38%. In addition, we have entered into a Brent-based hedge for 1,000 bbl/d at US$59.00/bbl.

For 2018, we have also entered into hedges on approximately 42% of our net WCS differential exposure at a price differential to WTI of US$14.19/bbl and 21% of our net natural gas exposure through a combination of AECO swaps at C$2.82/mcf and NYMEX swaps at US$3.02/mmbtu.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q3/2017 financial statements.

2017 Guidance

The following table summarizes our 2017 annual guidance and compares it to our 2017 year-to-date actual results.

	2017 Guidance			Variance to
	Original [1]	Current	YTD 2017	Current
Exploration and development capital ($ millions)	300 - 350	310 - 330	236.1	N/A
Production (boe/d)	66,000 - 70,000	69,500 - 70,000	70,473	1 %
Expenses:				
Royalty rate (%)	~23.0	~23.0	22.9	(1) %
Operating ($/boe)	11.00 - 12.00	~10.50	10.37	(1) %
Transportation ($/boe)	1.10 - 1.30	~1.40	1.37	(2) %
General and administrative ($/boe)	~2.00	~2.00	1.96	(2) %
Interest ($/boe)	~4.00	~4.00	3.93	(2) %

Notes:

(1) Original guidance as announced on December 12, 2016.

Board Appointment

The Board of Directors is pleased to announce the appointment of Mark Bly as a director of Baytex. Mr. Bly is an independent businessman with over 35 years of experience in the oil and gas industry, primarily with BP, a global producer of oil and gas. Since retiring from BP in 2013, Mr. Bly has worked with private oil and gas production and service companies serving as an executive, a board member and an advisor. At BP, Mr. Bly held various senior leadership roles in its domestic and international operations, including leading the North American onshore unit, Group Vice President for approximately 25% of BP's global production, and Executive Vice President of Group Safety and Operational Risk. Mr. Bly holds a Master of Science degree in structural engineering from the University of California, Berkeley and a Bachelor of Science degree in civil engineering from the University of California, Davis.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2017 and the related Management's Discussion and Analysis of the operating and financial results can be accessed immediately 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 Today – November 2 , 2017
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call today, November 2, 2017, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-866-226-4099 or international 1-647-427-2258. Alternatively, to listen to the conference call online, please enter http://edge.media-server.com/m/p/rryie6jh in your web browser.

An archived recording of the conference call will be available approximately two hours 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; our 2017 production and capital expenditure guidance; our Eagle Ford assets, including our assessment that it is a premier oil resource play, the initial production rates from new wells in Q3/2017; our Peace River assets, including that the area has some of the strongest capital efficiencies in the oil and gas industry and initial production rates from new wells in 2017; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; our target for exploration and development capital expenditures to approximate funds from operations; the effect that a strengthening Canada-U.S. dollar exchange rate will have on our U.S. dollar denominated debt; that our U.S. operations mitigate our exposure to fluctuations in the Canada-U.S. dollar exchange rate; our ability to partially reduce the volatility in our funds from operations by utilizing financial derivative contracts for commodity prices, heavy oil differentials and interest and foreign exchange rates; the percentage of our anticipated Q4/2017 and 2018 oil and natural gas production that is hedged; and our expected royalty rate and per boe operating, transportation, general and administrative and interest costs for 2017. 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 and contingent resources 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; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum 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; we may lose access to our 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, 2016, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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 Measures

Funds from operations 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. Funds from operations represents cash generated from operating activities adjusted for changes in non-cash operating working capital and asset retirement expenditures. Baytex's determination of funds from operations may not be comparable with the calculation of similar measures for other entities. Baytex considers funds from operations a key measure of performance as it demonstrates its ability to generate the cash flow necessary to fund capital investments and potential future dividends to shareholders. The most directly comparable measures calculated in accordance with GAAP are cash flow from operating activities and net income.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) 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.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in the credit agreement governing our revolving credit facilities. Bank EBITDA is used to measure compliance with certain financial covenants.

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 product revenue less royalties, production and operating expenses and transportation expenses 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.

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. 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.

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 80% 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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