BAYTEX REPORTS 2016 RESULTS, STRONG RESERVES GROWTH IN THE EAGLE FORD AND RESUMPTION OF DRILLING ACTIVITY IN CANADA

CALGARY, ALBERTA (March 7, 2017) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2016 (all amounts are in Canadian dollars unless otherwise noted).

“In 2016, we delivered on our production guidance while spending less than our original capital budget. We also significantly lowered our costs while taking steps to maintain strong levels of financial liquidity. In particular, I am pleased that our Eagle Ford assets continue to perform with proved plus probable reserves increasing 6% in 2016 resulting in 205% production replacement. We also improved Eagle Ford well costs to a record low US$4.5 million in the fourth quarter”, commented James Bowzer, Chief Executive Officer.

Ed LaFehr, President, said, “Our 2017 capital program is off to a strong start driven by larger fracture stimulations in the oil window of the Eagle Ford, the commencement of heavy oil drilling operations at Peace River and Lloydminster and increasing production from our recently acquired assets at Peace River. We are building operational momentum with production in the Eagle Ford up 5% in the first two months of 2017 as compared to Q4/2016, our first Peace River well producing approximately 600 bbl/d and our multi-lateral drilling at Lloydminster exceeding expectations. We expect to deliver 3-4% exit rate production growth this year.”

Highlights

- Generated production of 65,136 boe/d (79% oil and NGL) during Q4/2016 and 69,509 boe/d for the full-year 2016, in line with guidance;

- Delivered funds from operations ("FFO") of $77.2 million ($0.36 per share) in Q4/2016 and $276.3 million ($1.30 per share) for the full-year 2016. In 2016, FFO exceeded capital expenditures by $51 million;

- Decreased cash costs (operating expenses, transportation expenses and G&A expenses) by 8% on a boe basis;

- Reduced net debt (bank loan, long-term notes and working capital) by 13% to $1.8 billion;

- Replaced 205% of production in the Eagle Ford and increased proved plus probable reserves 6% to 216.5 mmboe. From the time of acquisition in June 2014, proved plus probable reserves in the Eagle Ford have increased by 30%;

- Improved Eagle Ford well costs to a record low US$4.5 million in Q4/2016 despite increasing frac stages and proppant usage and achieved a 20% increase in 30-day initial production rates in 2016 to 1,300 boe/d;

- Increased production in the Eagle Ford by approximately 5% in the first two months of 2017 to over 35,000 boe/d (from 33,432 boe/d in Q4/2016) as a result of the increased pace of development that commenced in Q4/2016;

- Initiated our Q1/2017 drilling program in Canada with our first multi-lateral horizontal well at Peace River generating a 30-day initial production rate of approximately 600 bbl/d, placing this well in the top decile of our historical Peace River results. In addition, our Lloydminster program is exceeding expectations;

- Acquired additional acreage in Peace River, more than doubling our land base and increasing our drilling inventory by 75%. At the time of closing on January 20, 2017, the assets were producing approximately 3,000 boe/d. Since closing, production has increased by approximately 10% as we initiated phase one of our plan to bring shut-in production back on-line; and

- Our net asset value at year-end 2016, discounted at 10%, is estimated to be $9.05 per share. This is based on the estimated reserves value of $3.9 billion plus a value for undeveloped acreage, net of long-term debt, asset retirement obligations and working capital.

	Three Months Ended			Years Ended	
	December 31, 2016	September 30, 2016	December 31, 2015	**December 31, 2016**	December 31, 2015
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 233,116**	$ 197,648	$ 229,362	**$ 780,095**	$ 1,121,424
Funds from operations (1)	**77,239**	72,106	93,095	**276,251**	516,417
Per share - basic	**0.36**	0.34	0.44	**1.30**	2.61
Per share - diluted	**0.36**	0.34	0.44	**1.30**	2.61
Net income (loss)	**(359,424)**	(39,430)	(419,175)	**(485,184)**	(1,142,880)
Per share - basic	**(1.66)**	(0.19)	(1.99)	**(2.29)**	(5.77)
Per share - diluted	**(1.66)**	(0.19)	(1.99)	**(2.29)**	(5.77)
Exploration and development	**68,029**	39,579	140,796	**224,783**	521,039
Acquisitions, net of divestitures	**(322)**	(62,752)	(574)	**(63,120)**	1,648
Total oil and natural gas capital expenditures	**$ 67,707**	$ (23,173)	$ 140,222	**$ 161,663**	$ 522,687
Bank loan (2)	**$ 191,286**	$ 289,859	$ 256,749	**$ 191,286**	$ 256,749
Long-term notes (2)	**1,584,158**	1,554,510	1,623,658	**1,584,158**	1,623,658
Long-term debt	**1,775,444**	1,844,369	1,880,407	**1,775,444**	1,880,407
Working capital (surplus) deficiency	**(1,903)**	19,653	169,498	**(1,903)**	169,498
Net debt (3)	**$ 1,773,541**	$ 1,864,022	$ 2,049,905	**$ 1,773,541**	$ 2,049,905

	Three Months Ended			Years Ended	
	December 31, 2016	September 30, 2016	December 31, 2015	**December 31, 2016**	December 31, 2015
OPERATING					
Daily production					
Heavy oil (bbl/d)	**22,982**	24,132	31,733	**23,586**	34,974
Light oil and condensate (bbl/d)	**20,163**	19,001	24,930	**21,377**	25,887
NGL (bbl/d)	**8,319**	9,149	8,996	**9,349**	8,492
Total oil and NGL (bbl/d)	**51,464**	52,282	65,659	**54,312**	69,353
Natural gas (mcf/d)	**82,032**	89,314	92,708	**91,182**	91,766
Oil equivalent (boe/d @ 6:1) (4)	**65,136**	67,167	81,110	**69,509**	84,648
Benchmark prices					
WTI oil (US$/bbl)	**49.29**	44.94	42.18	**43.33**	48.79
WCS heavy oil (US$/bbl)	**34.97**	31.44	27.69	**29.49**	35.26
Edmonton par oil ($/bbl)	**61.58**	54.80	52.94	**53.01**	57.20
LLS oil (US$/bbl)	**49.95**	45.82	43.33	**43.82**	51.50
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**34.33**	29.79	24.41	**26.46**	32.23
Light oil and condensate ($/bbl)	**60.12**	53.25	50.17	**50.32**	55.75
NGL ($/bbl)	**22.64**	14.96	17.23	**17.16**	16.91
Total oil and NGL ($/bbl)	**42.55**	35.72	33.21	**34.25**	39.13
Natural gas ($/mcf)	**3.61**	2.95	2.76	**2.69**	3.08
Oil equivalent ($/boe)	**38.16**	31.73	30.03	**30.29**	35.40
CAD/USD noon rate at period end	**1.3427**	1.3117	1.3840	**1.3427**	1.3840
CAD/USD average rate for period	**1.3339**	1.3051	1.3353	**1.3256**	1.2811

	Three Months Ended			Years Ended	
	December 31, 2016	September 30, 2016	December 31, 2015	**December 31, 2016**	December 31, 2015
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**7.35**	7.72	6.88	**9.04**	24.87
Low	**4.85**	4.76	3.50	**1.57**	3.50
Close	**6.56**	5.57	4.48	**6.56**	4.48
Volume traded (thousands)	**351,040**	377,435	283,619	**1,677,986**	652,044
NYSE					
Share price (US$)					
High	**5.61**	6.18	5.27	**7.14**	20.10
Low	**3.60**	3.59	2.50	**1.08**	2.50
Close	**4.48**	4.25	3.24	**4.48**	3.24
Volume traded (thousands)	**186,423**	168,984	153,763	**707,973**	375,660
Common shares outstanding (thousands)	**233,449**	211,542	210,583	**233,449**	210,583

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 other operating items. 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 year ended December 31, 2016.

(2) Principal amount of instruments.

(3) Net debt 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 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 exclude condensate blending.

Operating Results

Our operating results for the fourth quarter and full-year 2016 were consistent with our expectations and reflect limited drilling activity in Canada in response to the low crude oil price environment.

Production averaged 65,136 boe/d (79% oil and NGL) in Q4/2016, as compared to 67,167 boe/d (78% oil and NGL) in Q3/2016. For the full-year 2016, production averaged 69,509 boe/d (78% oil and NGL), in line with our production guidance range of 68,000 to 72,000 boe/d announced in March 2016 and subsequently tightened to 69,000 to 70,000 boe/d.

Capital expenditures for exploration and development activities totaled $63.0 million in Q4/2016 and $224.8 million for full-year 2016, in line with our guidance range of $225-$265 million announced in March 2016 and subsequently tightened to $200-$225 million. In 2016, we participated in the drilling of 142 (40.9 net) wells with a 100% success rate.

Eagle Ford

Our Eagle Ford assets in South Texas provide us with exposure to one of the premier oil resource plays in North America. The assets generate the highest cash netbacks in our portfolio with an inventory of development prospects in excess of 10 years at our current pace of development. In 2016, we focused almost all of our development activity in the Eagle Ford, directing 88% of our exploration and development expenditures on these assets.

Production was stable during the fourth quarter, averaging 33,432 boe/d (77% liquids), as compared to 33,552 boe/d in Q3/2016. During the fourth quarter, drilling activity increased at a pace consistent with our expectations. We averaged 3-4 drilling rigs and 1-2 completion crews on our lands. We are currently producing in excess of 35,000 boe/d in the Eagle Ford.

Cost reductions continued through the fourth quarter with wells being drilled, completed and equipped for approximately US$4.5 million, down 20% from approximately US$5.6 million in Q1/2016. These record low well costs were achieved despite increasing the number of frac stages and proppant usage. In Q4/2016, we increased the effective number of frac stages per well to 26 (22 in Q1/2016) and the amount of proppant per completed foot to 1,850 pounds (1,000 pounds in Q1/2016). Two recently completed pads utilizing higher intensity fracs in the crude oil window of our Longhorn acreage have shown a significant improvement in production rates compared to wells drilled previously.

In 2016, we participated in the drilling of 127 (36.9 net) wells, commenced production from 123 (36.3 net) wells and at year-end had 53 (14.9 net) wells waiting on completion. The wells that have been on production for more than 30 days established 30-day initial production rates of approximately 1,300 boe/d, which represents an approximate 20% improvement over 2015.

We increased our drilling rigs to five late in the fourth quarter and we currently have two completion crews working on our lands. We expect this level of activity to continue throughout 2017 bringing approximately 34 net wells on production.

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset for us since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, the area is recognized as having some of the strongest capital efficiencies in the oil and gas industry and, over the years, has contributed significantly to our growth. Production during the fourth quarter averaged approximately 15,000 boe/d (94% heavy oil). During 2016, we had limited activity on these lands as our development activity was focused on the Eagle Ford.

In November, we announced the strategic acquisition of additional heavy oil assets in Peace River. The assets are located immediately adjacent to our existing Peace River lands and more than doubled our land base in the area. The acquisition will drive efficiencies and synergies in our operations and significantly enhances our inventory of drilling locations for future growth. In total, we now have 350 potential drilling locations on our lands representing a drilling inventory of approximately 14 years. We closed the acquisition on January 20, 2017 for total consideration of $65 million. At the time of closing, the assets were producing approximately 3,000 boe/d.

Since closing the acquisition, production has increased by approximately 10% as we initiated phase one of our plan to bring approximately 3,000 boe/d of shut-in production back on-line. We have identified approximately 30 wells to be re-started, which will contribute to our target exit rate for the acquired assets of 3,500-4,000 boe/d. Phase two will include additional gas conservation and vapor recovery systems that are expected to be implemented over the next 12-24 months. We are also undertaking an extensive review of the operations to ensure regulatory compliance and identify opportunities to reduce operating costs. We anticipate meaningful improvements to the unit operating costs on these assets throughout 2017.

We have also initiated our 2017 drilling program at Peace River with two rigs currently running. The cost to drill, complete and equip a multi-lateral well at Peace River is approximately $2.5 million, which is an expected 11% improvement from the cost of the wells we drilled in Q3/2015. The first well from our 2017 program consisted of 13 laterals and came in approximately 7% below budget. This well was placed on production in early February and established a 30-day average initial production rate of approximately 600 bbl/d.

We plan to drill a total of 11 net multi-lateral horizontal wells and 8 net stratigraphic test wells at Peace River in 2017. We drill stratigraphic test wells to acquire full-section cores of the Bluesky formation which allows us to measure the permeability of the formation and the viscosity of the oil it contains over the cored interval. These measurements assist us in planning future drilling locations and the placement of the horizontal laterals.

Lloydminster

Our Lloydminster region straddles the Alberta and Saskatchewan border where we produced approximately 9,100 boe/d (98% heavy oil) during the fourth quarter. This area is characterized by multiple stacked pay formations at relatively shallow depths, which we have successfully developed through vertical drilling, horizontal drilling, waterflood and SAGD operations.

Consistent with Peace River, we had limited development activity at Lloydminster during 2016. Activity was focused on our non-operated assets where we participated in the drilling of 14 (2.98 net) vertical wells at Lindbergh. The cost to drill, complete and equip the vertical wells was budgeted at approximately $445,000 with resulting 30-day initial production rates of 40 bbl/d. The majority of these wells were brought on-stream in late 2016 and results have exceeded our expectations with 13 wells averaging 30-day initial production rates of 82 bbl/d.

In January, we commenced drilling operations on our operated lands for the first time in over a year and a half. With a focused effort on reducing our drilling and completion costs, we expect our Lloydminster heavy oil program to generate rates of return in excess of 75% at current commodity prices. We are now applying our multi-lateral drilling and production techniques from our Peace River region to Lloydminster, which we expect will lead to a 25% improvement in individual well capital efficiencies compared to single-lateral horizontal wells.

At Soda Lake, we have drilled six of eight multi-lateral horizontal wells planned for the first quarter of 2017 (16 multi-lateral horizontal wells are planned for the full-year). Depending on the overall length and completion, well costs range from $700,000 to $900,000 with an average 30-day initial production rate of approximately 130 bbl/d. Through efficient operational execution and lower service costs, the cost to drill, complete and equip our first six multi-lateral wells have come in approximately 15% below budget with 30-day initial production rates either meeting or exceeding expectations. Our most recent two wells are expected to generate 30-day initial production rates of approximately 175 bbl/d.

We plan to drill a total of 52 net wells at Lloydminster in 2017, of which approximately 30% will be multi-lateral horizontal wells. At this pace of development, we have a drilling inventory of over 10 years on these lands.

Financial Review

We generated FFO of $77.2 million ($0.36 per share) in Q4/2016, compared to $72.1 million ($0.34 per share) in Q3/2016. Full-year FFO was $276.3 million ($1.30 per share), compared to $516.4 million ($2.61 per share) in 2015. The decline in FFO on an annual basis is largely due to reduced production, lower commodity prices and lower realized hedging gains.

We recorded a net loss in Q4/2016 of $359.4 million ($1.66 per share) compared to a net loss of $39.4 million ($0.19 per share) in Q3/2016. The net loss in the quarter is largely attributable to non-cash impairment charges of $396.6 million.

Financial Liquidity

In 2016, we targeted our capital expenditures to approximate our FFO to minimize additional bank borrowings. We exceeded this goal as our FFO totaled $276.3 million, exceeding capital expenditures by $51.5 million. In Q4/2016, our FFO totaled $77.2 million, as compared to capital expenditures of $68.0 million. In 2016, we also disposed of certain non-core assets in Canada and the Eagle Ford for net proceeds of $63.1 million.

Our net debt (bank loan, long-term notes and working capital) has decreased to $1.8 billion at December 31, 2016 from $2.0 billion at December 31, 2015.

On March 31, 2016, we amended our credit facilities to provide us with increased financial flexibility. The amendments included reducing our credit facilities to US$575 million, granting our banking syndicate first priority security over our assets and restructuring our financial covenants. The revolving credit facilities, which currently mature in June 2019, are not borrowing base facilities and do not require annual or semi-annual reviews. Our Senior Secured Debt to Bank EBITDA ratio as at December 31, 2016 was 0.55:1.00 (maximum permitted ratio of 5.00:1.00) and our interest coverage ratio was 3.59:1.00 (minimum required ratio of 1.25:1.00).

Operating Netback

During the fourth quarter, our operating netback improved as compared to Q3/2016. In Q4/2016, the price for West Texas Intermediate light oil ("WTI") averaged US$49.29/bbl, as compared to US$44.94/bbl in Q3/2016. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, increased slightly during Q4/2016, averaging US$14.32/bbl, as compared to US$13.50/bbl in Q3/2016, mitigating a portion of the WTI increase on our realized prices.

We generated an operating netback in Q4/2016 of $19.24/boe ($17.62/boe excluding financial derivatives gain), as compared to $16.95/boe ($14.32/boe excluding financial derivatives gain) in Q3/2016. The Eagle Ford generated an operating netback of $24.34/boe during Q4/2016 while our Canadian operations generated an operating netback of $10.51/boe.

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

	Three Months Ended December 31					
	2016			2015		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Sales volume (boe/d)	**31,704**	**33,432**	**65,136**	40,826	40,284	81,110
Sales Price	**$ 31.10**	**$ 44.84**	**$ 38.16**	$ 23.59	$ 36.56	$ 30.03
Less:						
Royalties	**4.82**	**13.52**	**9.28**	2.72	10.56	6.61
Production and operating expenses	**13.10**	**6.98**	**9.96**	12.27	7.23	9.76
Transportation expenses	**2.67**	**—**	**1.30**	2.87	—	1.45
Operating netback	**$ 10.51**	**$ 24.34**	**$ 17.62**	$ 5.73	$ 18.77	$ 12.21
Financial derivatives gain	**—**	**—**	**1.62**	—	—	4.09
Operating netback after financial derivatives	**$ 10.51**	**$ 24.34**	**$ 19.24**	$ 5.73	$ 18.77	$ 16.30

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 $9.7 million in Q4/2016 due to crude oil and natural gas prices being at levels below those in our financial derivative contracts.

For 2017, we have entered into hedges on approximately 51% of our net WTI exposure with 10% fixed at US$54.46/bbl and 41% hedged utilizing a 3-way option structure that provides us with downside price protection at approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 33% of our net WCS differential exposure and 57% of our net natural gas exposure.

A complete listing of our financial derivative contracts can be found in Note 18 to our 2016 annual financial statements.

Outlook for 2017

2017 will be a year that builds operational momentum for Baytex through our three high quality resource plays. In Canada, after a drilling hiatus, we are already back to work with an active first quarter drilling program. In the Eagle Ford, we increased our rig activity at the end of 2016 and expect to maintain this increased level of development on our lands throughout 2017.

Our 2017 production guidance range is 66,000 to 70,000 boe/d with budgeted exploration and development capital expenditures of $300 to $350 million. Our expected exit production rate for 2017 reflects an organic growth rate of approximately 3-4% over the 2016 exit production rate. For the full-year, approximately 70% of our planned capital expenditures will be directed to our Eagle Ford operations. The balance of the spending will be in Canada, largely toward our heavy oil assets at Peace River and Lloydminster.

Year-end 2016 Reserves

Baytex's year-end 2016 proved and probable reserves were evaluated by Sproule Unconventional Limited ("Sproule") and Ryder Scott Company, L.P. ("Ryder Scott"), both independent qualified reserves evaluators. Sproule prepared our reserves report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's December 31, 2016 forecast price and cost assumptions. Ryder Scott also evaluated the possible reserves associated with our Eagle Ford assets. All Baytex oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"). Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2016, which will be filed on or before March 31, 2017.

Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Finding and development ("F&D") and finding, development and acquisition ("FD&A") costs are all reported inclusive of future development costs ("FDC").

Our 2016 reserves report does not include the acquisition of additional heavy oil assets in the Peace River region that closed on January 20, 2017.

2016 Highlights

Our Eagle Ford assets provide us with exposure to one of the premier oil resource plays in North America generating the highest cash netbacks in our portfolio with a significant inventory of development prospects. In 2016, we focused almost all of our development activity in the Eagle Ford, directing 88% of our capital expenditures on these assets. Our 2016 reserves report reflects this investment profile with continued growth in Eagle Ford reserves, offset by reduced reserves in Canada commensurate with lower activity levels.

- In the Eagle Ford, proved plus probable reserves increased 6% to 216.5 mmboe, replacing 205% of production. This includes the divestiture of 1.1 mmboe of proved plus probable reserves associated with our operated assets in July 2016. Since acquiring the assets in June 2014, we have increased our proved plus probable reserves in the Eagle Ford by 30%. We realized F&D costs in the Eagle Ford of $14.85/boe on a proved plus probable basis and a Q4/2016 operating netback of $24.34/boe (at a benchmark WTI price of US$49.29/bbl), which results in a recycle ratio of 1.6x.

- The following table highlights the capital efficiency of our 2016 Eagle Ford development program. A more detailed three-year summary of our corporate capital efficiencies can be found on page 16.

Efficiency of our 2016 Eagle Ford Capital Development Program (Excluding Divestitures)

Exploration and Development Expenditures ($ millions)	$	198.9
Change in Proved plus Probable FDC ($ millions)		211.4
Total ($ millions)	$	410.3
Proved plus Probable Reserves Additions (mboe) (1)		27,632
F&D costs ($/boe)	$	14.85
Production Replacement Ratio (2)		206%
Recycle Ratio (3)		1.6x

Notes:

(1) Reserves additions are net of technical revisions.

(2) Production Replacement ratio is calculated as total reserves additions divided by annual production.

(3) Recycle ratio is calculated as operating netback divided by F&D costs (proved plus probable including FDC). Operating netback is calculated as revenue less royalties, operating expenses and transportation expenses. In Q4/2016, the Eagle Ford realized an operating netback of $24.34/boe based on an average benchmark WTI price of US$49.29/bbl.

- Due to the low oil price environment, we did not engage in any reserves generating activity on our heavy oil assets in Canada, deferring all operated drilling activity, including development wells and stratigraphic test wells. This reduced level of activity in Canada resulted in limited reserves additions, which when combined with production, economic factors and technical revisions resulted in a 20% reduction in proved plus probable reserves associated with our heavy oil assets.

- Using the December 31, 2016 independent reserves evaluation, the present value of our reserves, discounted at 10% before tax, is estimated to be $3.9 billion (as compared to $4.3 billion at year-end 2015). The reduction in the present value of reserves is largely attributable to the year-over-year reduction in forecast price assumptions used by Sproule.

- Our net asset value at year-end 2016, discounted at 10%, is estimated to be $9.05 per share. This is based on the estimated reserves value of $3.9 billion plus a value for undeveloped acreage, net of long-term debt, asset retirement obligations and working capital.

- In aggregate, proved plus probable reserves decreased 3% to 406 mmboe and proved reserves decreased 8% to 253 mmboe. Year-end 2016 proved plus probable reserves are comprised of 79% oil and NGL and 21% natural gas.

- Proved developed producing ("PDP") reserves represent 39% of proved reserves (40% at year-end 2015) and proved reserves represent 62% of proved plus probable reserves (66% at year-end 2015).

- We realized F&D costs of $19.33/boe in 2016 on a proved plus probable basis, and a three-year average (2014-2016) of $16.79/boe. Our three-year average (2014-2016) recycle ratio is 1.9x. We realized FD&A costs of $18.33/boe on a proved plus probable basis in 2016, and a three-year average (2014-2016) of $27.86/boe.

- We enhanced our reserves life index, excluding thermal reserves, to 4.1 years on a PDP basis (3.7 years at year-end 2015), 10.1 years on a proved basis (8.8 years at year-end 2015) and 14.2 years (11.7 years at year-end 2015) on a proved plus probable basis, which is calculated using annualized Q4/2016 production.

The following table reconciles the change in reserves during 2016 by reserves category and operating area.

(gross reserves, mmboe)	**Eagle Ford**	**Heavy Oil**	**Canada Conventional**	**Total Excluding Thermal**	**Thermal**	**Total**
Proved Developed Producing						
December 31, 2015	60.3	37.2	10.6	108.1	0.5	108.6
Additions, net of revisions	13.9	(0.5)	1.5	14.9	0.5	15.4
Production	(13.4)	(8.4)	(3.1)	(24.9)	(0.6)	(25.4)
December 31, 2016	60.8	28.3	9.0	98.1	0.4	98.5
% Change	1%	(24%)	(15%)	(9%)	(20%)	(9%)
Proved						
December 31, 2015	174.9	68.4	17.6	260.9	13.8	274.8
Additions, net of revisions	6.6	(4.8)	1.4	3.2	0.3	3.5
Production	(13.4)	(8.4)	(3.1)	(24.9)	(0.6)	(25.4)
December 31, 2016	168.1	55.2	15.9	239.2	13.5	252.7
% Change	(4%)	(19%)	(10%)	(8%)	(2%)	(8%)
Proved Plus Probable						
December 31, 2015	203.4	106.8	36.8	347.0	69.6	416.6
Additions, net of revisions	26.5	(13.4)	1.6	14.7	0.3	14.9
Production	(13.4)	(8.4)	(3.1)	(24.9)	(0.6)	(25.4)
December 31, 2016	216.5	85.0	35.3	336.8	69.3	406.1
% Change	6%	(20%)	(4%)	(3%)	(1%)	(3%)

Petroleum and Natural Gas Reserves as at December 31, 2016

The following table sets forth our gross and net reserves volumes at December 31, 2016 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA	Forecast Prices and Costs					
	Heavy Oil		Bitumen		Light and Medium Oil	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)
Proved						
Developed Producing	25,923	19,717	382	347	1,985	1,858
Developed Non-Producing	2,609	2,223	7,655	7,072	—	—
Undeveloped	18,343	16,172	5,428	4,357	308	316
Total Proved	46,875	38,112	13,465	11,776	2,293	2,174
Probable	29,325	23,955	55,835	44,311	1,794	1,598
Total Proved Plus Probable	76,199	62,068	69,300	56,086	4,087	3,773

CANADA	Forecast Prices and Costs					
	Natural Gas Liquids[3]		Conventional Natural Gas[4]		Oil Equivalent[5]	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)	Gross[1] (mboe)	Net[2] (mboe)
Proved						
Developed Producing	1,246	925	49,201	43,294	37,735	30,063
Developed Non-Producing	—	—	22	35	10,267	9,302
Undeveloped	1,345	1,114	66,711	60,907	36,542	32,110
Total Proved	2,590	2,039	115,933	104,236	84,544	71,475
Probable	3,198	2,479	89,206	76,579	105,019	85,106
Total Proved Plus Probable	5,788	4,518	205,139	180,816	189,564	156,581

UNITED STATES	Forecast Prices and Costs					
	Tight Oil		Natural Gas Liquids[3]		Shale Gas	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)
Proved						
Developed Producing	19,242	14,101	26,907	19,861	60,929	45,025
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	30,472	22,344	53,194	39,199	112,899	83,277
Total Proved	49,714	36,444	80,102	59,059	173,828	128,302
Probable	8,399	6,161	28,627	21,025	59,075	43,371
Total Proved Plus Probable	58,113	42,605	108,728	80,084	232,903	171,674
Possible[6][7]	19,269	14,160	37,430	27,545	81,346	59,866
Total Proved Plus Probable Plus Possible	77,381	56,765	146,158	107,629	314,249	231,540

UNITED STATES

Forecast Prices and Costs

Reserves Category	Conventional Natural Gas[4] Gross[1] (mmcf)	Conventional Natural Gas[4] Net[2] (mmcf)	Oil Equivalent[5] Gross[1] (mboe)	Oil Equivalent[5] Net[2] (mbbl)
Proved				
Developed Producing	27,530	20,206	60,892	44,833
Developed Non-Producing	—	—	—	—
Undeveloped	28,553	20,950	107,242	78,914
Total Proved	56,083	41,156	168,134	123,747
Probable	8,906	6,543	48,355	35,505
Total Proved Plus Probable	64,988	47,699	216,490	159,252
Possible[6][7]	18,327	13,477	73,310	53,928
Total Proved Plus Probable Plus Possible	83,315	61,176	289,800	213,180

TOTAL

Forecast Prices and Costs

Reserves Category	Heavy Oil Gross[1] (mbbl)	Heavy Oil Net[2] (mbbl)	Bitumen Gross[1] (mbbl)	Bitumen Net[2] (mbbl)	Light and Medium Oil Gross[1] (mbbl)	Light and Medium Oil Net[2] (mbbl)
Proved						
Developed Producing	25,923	19,717	382	347	1,985	1,858
Developed Non-Producing	2,609	2,223	7,655	7,072	—	—
Undeveloped	18,343	16,172	5,428	4,357	308	316
Total Proved	46,875	38,112	13,465	11,776	2,293	2,174
Probable	29,325	23,955	55,835	44,311	1,794	1,598
Total Proved Plus Probable	76,199	62,068	69,300	56,086	4,087	3,773
Possible[6][7]	—	—	—	—	—	—
Total Proved Plus Probable Plus Possible	76,199	62,068	69,300	56,086	4,087	3,773

TOTAL

Forecast Prices and Costs

Reserves Category	Tight Oil Gross[1] (mbbl)	Tight Oil Net[2] (mbbl)	Natural Gas Liquids[3] Gross[1] (mbbl)	Natural Gas Liquids[3] Net[2] (mbbl)	Shale Gas Gross[1] (mmcf)	Shale Gas Net[2] (mmcf)
Proved						
Developed Producing	19,242	14,101	28,153	20,786	60,929	45,025
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	30,472	22,344	54,539	40,312	112,899	83,277
Total Proved	49,714	36,444	82,692	61,099	173,828	128,302
Probable	8,399	6,161	31,825	23,504	59,075	43,371
Total Proved Plus Probable	58,113	42,605	114,516	84,602	232,903	171,674
Possible[6][7]	19,269	14,160	37,430	27,545	81,346	59,866
Total Proved Plus Probable Plus Possible	77,381	56,765	151,946	112,147	314,249	231,540

TOTAL	**Forecast Prices and Costs**			
	Conventional Natural Gas(4)		**Oil Equivalent(5)**	
Reserves Category	**Gross(1) (mmcf)**	**Net(2) (mmcf)**	**Gross(1) (mboe)**	**Net(2) (mboe)**
Proved				
Developed Producing	76,731	63,501	98,627	74,896
Developed Non-Producing	21	35	10,267	9,302
Undeveloped	95,264	81,857	143,784	111,024
Total Proved	172,016	145,392	252,678	195,222
Probable	98,112	83,123	153,375	120,611
Total Proved Plus Probable	270,127	228,515	406,053	315,832
Possible(6)(7)	18,327	13,477	73,310	53,928
Total Proved Plus Probable Plus Possible	288,455	241,992	479,364	369,760

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

(5) 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.

(6) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(7) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves [1][2]
By Principal Product Type
Forecast Prices and Costs

	Heavy Oil[3]			Bitumen		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640
Extensions	227	1,255	1,482	—	—	—
Infill Drilling	1,037	1,024	2,062	—	—	—
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(8,004)	(9,862)	(17,866)	476	(216)	260
Discoveries	—	—	—	—	—	—
Acquisitions	34	13	48	—	—	—
Dispositions	(685)	(804)	(1,489)	—	—	—
Economic Factors	(2,700)	(185)	(2,885)	(204)	170	(35)
Production	(8,065)	—	(8,065)	(565)	—	(565)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300

	Light and Medium Crude Oil			Tight Oil[4]		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**
December 31, 2015	2,902	2,420	5,323	49,215	4,551	53,765
Extensions	—	—	—	—	—	—
Infill Drilling	—	—	—	6,948	5,863	12,812
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	141	(425)	(284)	(1,723)	(2,027)	(3,750)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(25)	(8)	(32)	(831)	(52)	(883)
Economic Factors	(214)	(194)	(408)	3	63	67
Production	(511)	—	(511)	(3,898)	—	(3,898)
December 31, 2016	2,293	1,794	4,087	49,714	8,399	58,113

	Natural Gas Liquids[4][5]			Shale Gas[4]		
Gross Reserves Category	**Proved (mbbl)**	**Probable (mbbl)**	**Proved + Probable (mbbl)**	**Proved (mmcf)**	**Probable (mmcf)**	**Proved + Probable (mmcf)**
December 31, 2015	86,454	19,344	105,798	194,767	40,038	234,805
Extensions	—	148	148	—	—	—
Infill Drilling	15,692	21,905	37,597	33,171	43,893	77,064
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	(12,676)	(9,662)	(22,338)	(41,058)	(25,187)	(66,246)
Discoveries	—	—	—	—	—	—
Acquisitions	106	27	133	—	—	—
Dispositions	(149)	(24)	(174)	—	—	—
Economic Factors	95	88	183	334	331	665
Production	(6,830)	—	(6,830)	(13,386)	—	(13,386)
December 31, 2016	82,692	31,825	114,516	173,828	59,075	232,903

Gross Reserves Category	Conventional Natural Gas[6][7] Proved (mmcf)	Conventional Natural Gas[6][7] Probable (mmcf)	Conventional Natural Gas[6][7] Proved + Probable (mmcf)	Oil Equivalent[8] Proved (mboe)	Oil Equivalent[8] Probable (mboe)	Oil Equivalent[8] Proved + Probable (mboe)
December 31, 2015	148,880	91,529	240,409	274,633	142,008	416,640
Extensions	11	3,682	3,693	229	2,017	2,245
Infill Drilling	7,749	5,094	12,843	30,497	36,957	67,455
Improved Recoveries	—	—	—	—	—	—
Technical Revisions	36,875	520	37,395	(22,483)	(26,303)	(48,786)
Discoveries	—	—	—	—	—	—
Acquisitions	2,531	641	3,172	562	147	709
Dispositions	(2,615)	(619)	(3,235)	(2,126)	(992)	(3,118)
Economic Factors	(1,428)	(2,735)	(4,163)	(3,202)	(460)	(3,661)
Production	(19,987)	—	(19,987)	(25,431)	—	(25,431)
December 31, 2016	172,016	98,112	270,127	252,679	153,375	406,053

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Reserves information as at December 31, 2016 and 2015 is prepared in accordance with NI 51-101.

(3) Technical revisions related to heavy oil are largely attributable to revised reservoir and mobility mapping and well performance.

(4) Technical revisions for tight oil, natural gas liquids and shale gas were largely the result of the development of additional horizons, primarily the Upper Eagle Ford. These new horizons are now proven and have producing wells and new locations, which reduced the expected recovery from a portion of the existing wells. These technical revisions were more than offset by reserve additions classified as "infill drilling".

(5) Natural gas liquids include condensate.

(6) Conventional natural gas includes associated, non-associated and solution gas.

(7) Technical revisions related to conventional natural gas are largely attributable to solution gas conservation at Peace River.

(8) 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.

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves (excluding thermal reserves) at year-end 2016 by annualized Q4/2016 production.

	Q4/2016 Actual Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	51,464	9.7	13.5
Natural Gas (mcf/d)	82,032	11.6	16.8
Oil Equivalent (boe/d)	65,136	10.1	14.2

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital programs (including FDC) is summarized in the following table.

	2016	2015	2014	Three-Year Total / Average 2014 - 2016
Capital Expenditures ($ millions)				
Exploration and development	$ 224.8	$ 521.0	$ 766.1	$ 1,511.9
Acquisitions (net of dispositions)	(63.6)	1.6	2,545.1	2,483.1
Total	$ 161.2	$ 522.7	$ 3,311.2	$ 3,995.0
Change in Future Development Costs – Proved ($ millions)				
Exploration and development	$ (219.4)	$ (397.9)	$ (248.5)	$ (865.8)
Acquisitions (net of dispositions)	7.6	6.0	1,312.9	1,326.5
Total	$ (211.8)	$ (391.9)	$ 1,064.4	$ 460.7
Change in Future Development Costs – Proved plus Probable ($ millions)				
Exploration and Development	$ 108.8	$ (399.9)	$ (102.0)	$ (393.1)
Acquisitions (net of dispositions)	1.9	0.5	1,210.5	1,1212.9
Total	$ 110.7	$ (399.4)	$ 1,108.5	$ 819.8
Proved Reserves Additions (mboe)				
Exploration and development	5,041	21,729	83,515	110,285
Acquisitions (net of dispositions)	(1,564)	537	68,824	67,797
Total	3,477	22,266	152,339	178,082
Proved plus Probable Reserves Additions (mboe)				
Exploration and development	17,253	15,782	33,598	66,633
Acquisitions (net of dispositions)	(2,408)	126	108,515	106,233
Total	14,844	15,908	142,113	172,865
F&D costs ($/boe) (1)				
Proved	$ 1.07	$ 5.67	$ 6.20	$ 5.86
Proved plus probable	$ 19.33	$ 7.68	$ 19.77	$ 16.79
FD&A costs ($/boe) (2)				
Proved	$ — (5)	$ 5.88	$ 28.72	$ 25.02
Proved plus probable	$ 18.33	$ 7.75	$ 31.10	$ 27.86
Ratios (based on proved plus probable reserves)				
Production replacement ratio(3)	58%	52%	497%	204%
Recycle ratio (4)	1.0x	2.9x	1.9x	1.9x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures) divided by total reserves additions.

(3) Production Replacement Ratio is calculated as total reserves additions (including acquisitions and divestitures) divided by annual production.

(4) Recycle Ratio is calculated as operating netback divided by F&D costs (proved plus probable including FDC). Operating netback is calculated as revenue (including realized hedging gains and losses) minus royalties, operating expenses and transportation expenses. For 2016, recycle ratio is calculated based on a Q4/2016 operating netback of $19.24/boe.

(5) 2016 FD&A costs were negative due to the reduction in estimated Future Development Costs.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes Sproule and Ryder Scott's estimate of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

Summary of Net Present Value of Future Net Revenue
As at December 31, 2016
Forecast Prices and Costs
Before Income Taxes and Discounted at (%/year)

CANADA

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 523,531	$ 467,725	$ 420,445	$ 381,377	$ 349,129
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	534,063	386,333	283,491	210,063	156,424
Total Proved	1,300,931	1,022,460	825,145	681,804	575,038
Probable	2,182,301	1,195,885	723,254	467,328	314,943
Total Proved Plus Probable	$ 3,483,233	$ 2,218,345	$ 1,548,399	$ 1,149,132	$ 889,981

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,674,035	$ 1,286,547	$ 1,047,642	$ 888,644	$ 776,258
Developed Non-Producing					
Undeveloped	2,328,597	1,416,589	914,698	615,838	426,453
Total Proved	4,002,633	2,703,136	1,962,340	1,504,482	1,202,712
Probable	1,053,807	604,633	376,915	249,067	171,338
Total Proved Plus Probable	5,056,440	3,307,769	2,339,255	1,753,549	1,374,049
Possible (1)	2,370,364	1,417,370	938,108	668,947	504,293
Total Proved Plus Probable Plus Possible (1)	$ 7,426,804	$ 4,725,138	$ 3,277,363	$ 2,422,496	$ 1,878,343

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 2,197,567	$ 1,754,271	$ 1,468,087	$ 1,270,022	$ 1,125,387
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	2,862,660	1,802,922	1,198,190	825,901	582,878
Total Proved	5,303,564	3,725,596	2,787,485	2,186,286	1,777,750
Probable	3,236,109	1,800,518	1,100,168	716,395	486,281
Total Proved Plus Probable	8,539,673	5,526,114	3,887,653	2,902,681	2,264,031
Possible (1)(2)	2,370,364	1,417,370	938,108	668,947	504,293
Total Proved Plus Probable Plus Possible (1)(2)	$ 10,910,037	$ 6,943,484	$ 4,825,762	$ 3,571,628	$ 2,768,324

Notes:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used by Sproule in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2016.

Year	WTI Cushing US$/bbl	Canadian Light Sweet C$/bbl	Western Canada Select C$/bbl	Henry Hub US$/MMbtu	AECO-C Spot C$/MMbtu	Operating Cost Inflation Rate %/Yr	Capital Cost Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2016 act.	43.32	52.80	38.30	2.55	2.18	1.6	(3.3)	0.755
2017	55.00	65.58	53.12	3.50	3.44	0.0	0.0	0.780
2018	65.00	74.51	61.85	3.50	3.27	2.0	2.0	0.820
2019	70.00	78.24	64.94	3.50	3.22	2.0	2.0	0.850
2020	71.40	80.64	66.93	4.00	3.91	2.0	2.0	0.850
2021	72.83	82.25	68.27	4.08	4.00	2.0	2.0	0.850
2022	74.28	83.90	69.64	4.16	4.10	2.0	2.0	0.850
2023	75.77	85.58	71.03	4.24	4.19	2.0	2.0	0.850
2024	77.29	87.29	72.45	4.33	4.29	2.0	2.0	0.850
2025	78.83	89.03	73.90	4.42	4.40	2.0	2.0	0.850
2026	80.41	90.81	75.38	4.50	4.50	2.0	2.0	0.850
2027	82.02	92.63	76.88	4.59	4.61	2.0	2.0	0.850
Thereafter	Escalation rate of 2.0%							

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs
As of December 31, 2016
Forecast Prices and Costs
($000s)

	CANADA		UNITED STATES		TOTAL	
	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2017	68,851	82,101	171,137	252,541	239,989	334,642
2018	130,105	273,039	192,088	247,526	322,193	520,564
2019	118,115	279,336	200,143	267,560	318,258	546,896
2020	63,573	162,254	168,708	245,334	232,280	407,588
2021	36,081	138,682	215,465	282,523	251,546	421,204
Remaining	15,550	303,996	395,073	551,698	410,623	855,693
Total (undiscounted)	432,275	1,239,406	1,342,613	1,847,182	1,774,888	3,086,588

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2016.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	554,178	489,669
Saskatchewan	119,004	113,440
Total Canada	673,182	603,109
United States		
Texas	3,038	2,535
Total Company	676,220	605,644

We estimate the value of our net undeveloped land holdings at December 31, 2016 to be approximately $67 million. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before tax, as estimated by the Company's independent reserves engineers, Sproule and Ryder Scott, at year-end, plus the estimated value of our undeveloped acreage, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves evaluators.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of possible reserves or contingent resources. As we execute our capital programs, we expect to convert possible reserves and contingent resources to reserves which may result in an increase in booked proved plus probable reserves.

The following table sets forth our net asset value as at December 31, 2016.

	Net Asset Value Forecast Prices and Costs (before tax) and Discounted at (%/year)		
($ millions except per share amounts)	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$ 5,526	$ 3,888	$ 2,903
Undeveloped acreage (1)	67	67	67
Asset retirement obligations (2)	(136)	(69)	(46)
Net debt	(1,774)	(1,774)	(1,774)
Net Asset Value	$ 3,683	$ 2,112	$ 1,150
Net Asset Value per Share (3)	$ 15.78	$ 9.05	$ 4.93

Notes:

(1) Undeveloped acreage value generally represents the estimated replacement cost of our undeveloped land.
(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.
(3) Based on 233.4 million common shares outstanding as at December 31, 2016.

Contingent Resources Assessment

We commissioned Sproule to conduct an evaluation of our contingent resources in the Lloydminster, Peace River, Northeast Alberta and Pembina areas in Canada. We commissioned Ryder Scott to audit our internal evaluation of our contingent resources in the Eagle Ford area of Texas. Both assessments were effective December 31, 2016, and were prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

Contingent resources represent the quantity of oil and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of our contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided are estimates. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided.

The contingent resources described below represent our gross interests (unless otherwise indicated) and are a best estimate. A “best estimate” is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources identified in the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources herein are presented as deterministic cumulative best estimate volumes.

Our contingent resources fall within the development pending and development unclarified sub-classes, which are defined as follows:

- Development Pending – are economic contingent resources that have a high chance of development. Contingencies are directly influenced by the developer, are actively being pursued and resolution is expected in a reasonable time period.

- Development Unclarified – are contingent resources that have a chance of development which is difficult to assess, and have an economic status which is undetermined. Projects are currently under evaluation and therefore contingencies are not clearly defined. Progress is expected within a reasonable time period.

Development Pending

The following table summarizes the status of our development pending contingent resources.

Development Pending - Project Status

Area	Product Type	Project Status	Future Development Costs ($ millions)[1]	Timing of First Commercial Production	Recovery Technology
Peace River	Bitumen	Development Study	$129	2019-2021	Cyclic steam stimulation ("CSS")
Peace River, Lloydminster and Northeast Alberta	Heavy Oil	Development Study	$94	2017-2023	Horizontal, vertical and multilateral well development
Pembina	Light & Medium Oil, Natural Gas	Development Study	$13	2022	Horizontal well development with multi-stage fracturing completion
Eagle Ford	Tight Oil, Shale Gas and NGL	Development Study	$152	2017-2028	Horizontal well development with multi-stage fracturing completion

Note:

(1) Undiscounted and unrisked.

The following table presents a summary of the quantitative risk of the chance of development we have applied to our development pending contingent resources.

Development Pending - Chance of Development Risk [1]

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)	Risked NPV [2] Discounted at 10% (before tax) ($ millions)
Peace River	Bitumen	19	81%	16	70
Peace River, Lloydminster and Northeast Alberta	Heavy Oil	6	86%	5	23
Pembina	Light & Medium Oil, Natural Gas	2	90%	2	10
Eagle Ford	Tight Oil, Shale Gas and NGL	14	80%	11	107
Total		41		34	210

Notes:

(1) Numbers may not add due to rounding.
(2) An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.

The principal risks that would influence the development of the Lloydminster, Northeast Alberta, Peace River and Pembina development pending contingent resources are: the timing of regulatory approvals to expand the project areas; the results of delineation drilling and seismic activity necessary for project development; the ability of these projects to compete for capital against our other projects; our corporate commitment to the timing of development; and the commodity price levels affecting the economic viability bitumen and heavy oil production in Alberta. The principal risks specific to the development of the Eagle Ford development pending contingent resources are: our reliance on the operator's capital commitment and development timing; the ability of these projects to compete for capital against our other projects; and the possibility of inter-well communication from infill drilling.

Development Unclarified

Our development unclarified contingent resources are conceptual project scenarios with no specific company defined development plan in the near-term. The following table presents a summary of the quantitative risk of the chance of development we have applied to our development unclarified contingent resources.

Development Unclarified - Chance of Development Risk (1)

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)
Peace River and Northeast Alberta	Bitumen	943	58%	551
Peace River, Lloydminster and North East Alberta	Heavy Oil	29	56%	16
Pembina	Light & Medium Oil, Natural Gas	12	55%	7
Eagle Ford	Tight Oil, Shale Gas and NGL	120	50%	60
Total		1,103		634

Note:

(1) Numbers may not add due to rounding.

In addition to the risks identified for the development pending sub-class, the projects in the Lloydminster, Northeast Alberta, Peace River and Pembina areas development unclarified sub-class are also subject to risks pertaining to commercial productivity of the reservoirs. The geological complexity and variability in these reservoirs may require the implementation of pilot projects to test the viability of CSS and SAGD thermal recovery technologies. The risks outlined for the contingent resources in the Eagle Ford development pending sub-class also apply to the development unclarified sub-class but are greater in magnitude.

Additional disclosures related to our contingent resources will be included in Appendix A to our Annual Information Form for the year ended December 31, 2016, which will be filed on or before March 31, 2017.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2016 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
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call today, March 7, 2017, starting at 9:00am MST (11:00am EST). 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/5af7rwtb 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 2016-2017 exit production organic growth rate; our Eagle Ford assets, including our assessment that it is a premier oil resource play, our inventory of development prospects (in years based on 2017 activity levels), the cost to drill, complete and equip a well, the performance of wells drilled in the Eagle Ford in Q1/2017, initial production rates from new wells, the number of drilling rigs and frac crews working on our lands during 2017 and the number of wells we plan to bring on production in 2017; our Peace River assets, including that the area has some of the strongest capital efficiencies in the oil and gas industry, our inventory of potential drilling locations, the cost to drill, complete and equip a well and the number of multi-lateral and stratigraphic test wells to be drilled in 2017; our recently completed acquisition at Peace River, including that it will drive efficiencies and synergies in our operations, that it significantly increases our drilling inventory, our plan for bringing shut-in production volumes back on-line, the 2017 exit production rate for the acquired assets and our expectation that we will achieve meaningful improvements to the unit operating costs in 2017; our Lloydminster assets, including the cost to drill, complete and equip both vertical and multi-lateral horizontal wells, initial production rates from both vertical and multi-lateral horizontal wells, the expected rate of return from drilling new wells, our expectation that multi-lateral drilling will improve individual well capital efficiencies; the number and type of wells to be drilled in 2017 and our inventory of drilling prospects (in years based on 2017 activity levels); our liquidity and financial capacity; our ability to partially reduce the volatility in our funds from operations by utilizing financial derivate contracts for commodity prices, heavy oil differentials and interest and foreign exchange rates; the proportion of our anticipated 2017 oil and natural gas production that is hedged; that 2017 will be a year in which we build operational momentum; our annual average production rate for 2017; our exploration and development capital expenditure budget for 2017; the breakdown of our 2017 capital expenditure budget by geographic area; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for oil and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings; our estimated net asset value; our development pending contingent resources, including future development costs, timing of first commercial production, risked and unrisked volumes, chance of development and the net present value before income taxes of the future net revenue; and our development unclarified contingent resources, including risked and unrisked volumes and chance of development. 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.

Non-GAAP Financial and Capital Management 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 other operating items. 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

The reserves information contained in this press release has been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2016, which will be filed on or before March 31, 2017. Listed below are cautionary statements that are specifically required by NI 51-101:

- *Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

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

- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

This press release contains metrics commonly used in the oil and natural gas industry, such as “recycle ratio,” “operating netback,” and “reserve life index.” These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex’s performance, however, such measures are not reliable indicators of Baytex’s future performance and future performance may not compare to Baytex’s performance in previous periods and therefore such metrics should not be unduly relied upon.

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex’s total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. At the Eagle Ford, our net drilling locations include 201 proved, 81 probable and 283 unbooked locations. At Peace River, our net drilling locations include 116 proved, 54 probable and 180 unbooked locations (which include locations attributable to the assets acquired on January 20, 2017, which were based on an internal evaluation prepared by a qualified reserves evaluator and are not included in the 2016 reserves report). At Lloydminster, our net drilling locations include 279 proved, 103 probable and 252 unbooked locations.

This press release contains estimates as of December 31, 2016 of the volumes of "contingent resources" attributable to our properties. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future.

The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

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.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" and "possible reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves" and permits the optional disclosure of "possible reserves". Additionally, NI 51-101 defines "proved reserves", "probable reserves" and "possible reserves" differently from the SEC rules. Accordingly, proved, probable and possible reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves. Possible reserves are higher risk than probable reserves and are generally believed to be less likely to be accurately estimated or recovered than probable reserves.

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

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve *estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.*

We also included in this press release estimates of contingent resources. Contingent resources represent the quantity of petroleum and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The SEC does not permit the inclusion of estimates of resource in reports filed with it by United States companies.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

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 79% 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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